
Damage
To
Underwater
Pipelines
International Workshop
Feb. 22 thru 24, 1995
New Orleans, Louisiana

PROCEEDINGS OF THE INTERNATIONAL WORKSHOP ON DAMAGE TO UNDERWATER PIPELINES

held on
22-24 February 1995

at the
Doubletree Hotel, 300 Canal Street, New Orleans, U.S.A.

Primary Sponsors:
Minerals Management Service, U.S. Department of the Interior
Office of Pipeline Safety, U.S. Department of Transportation

Co-Sponsors:
American Gas Association
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DISCLAIMER

The contents of these proceedings reflect the views of the individual authors and presenters, who are responsible for the individual opinions, findings, recommendations and conclusions (if any) contained herein. The contents do not reflect the official views or policies of the sponsors, nor do the contents necessarily reflect the views of the steering committee, the keynote speakers, or the working group chairmen whose function was mainly to act as a catalyst for discussion. The contents do not in any way constitute a standard, specification, or regulation of any kind.

TERMS OF REFERENCE

The ability to cope safely with damage to offshore pipelines has become a major responsibility of the modern oil and gas industry, in order to sustain safe operations, secure environmental quality, and maintain efficient utilization of resources. Recent examples have included fires caused by pipeline damage from jack-up platform legs, and oil spills from pipes ruptured by river flooding. Other less dramatic events can be equally significant in terms of operational or environmental considerations. Mud slides, dropped objects, and anchor drags among other causes have all been responsible for significant damage. An important test of the emergency performance of large pipeline systems also occurred in 1992, when Hurricane Andrew passed over the Northern Gulf of Mexico.

These issues apply equally to pipelines that traverse coastal waterways, lakes, rivers or canals. Design and mitigation measures and repair techniques are common concerns for all underwater pipelines. This workshop was held in order to provide a forum for collaboration among professionals working in this field, and to bring together the various parties active in this field, to provide definition of areas for management and research focus, and to form a written record of the major issues at this point in time. The overall purpose was to discuss current practice, share progress, identify desirable future activities and agree on key future directions in the offshore & underwater pipeline industry.

A steering committee was therefore set up to provide a broad base of industry and agency input into the planning of the workshop. This included representation from (among other organizations) :-

Minerals Management Service
Department of Transportation
U.S. Coast Guard
Canadian National Energy Board
Major Oil Companies
Gas Transmission Companies
Offshore Construction Companies
Pipeline Engineering Companies
Major Research Universities
Southern Gas Association
Interstate Natural Gas Association of America
American Petroleum Institute

The steering committee identified five special topics as being of particular importance, and these were as follows:-

1. Regulatory Issues

2. Operational & Other Damage

3. Reliability Design for New & Existing Pipelines

4. Repair Considerations

5. Response to Abnormal Situations

A two and one-half day program was organized for the workshop on Wed. 22 through Fri. 24 February 1995 at the Doubletree Hotel and conference center in downtown New Orleans. A series of keynote addresses and invited lectures were initially given by a number of international experts on a variety of relevant topics. This was followed by a special workshop on the "partnering" process. Thereafter, simultaneous working group sessions took place, through the second day. Participants were able to attend more than one working group, and were also encouraged where appropriate to bring position papers and written contributions. Participation in the workshop included representatives of the gas and petroleum industry, consulting firms, offshore contractors, manufacturers and fabricators, government agencies, and academic and research institutions. The conclusions of the working groups were then presented for open discussion on the third day.

The invited lectures and working group discussions and recommendations were used as the basis for the published proceedings contained herein. This report provides the written record of the invited papers and the subsequent results and conclusions of each of the working groups, as well as some independent contributions. The views expressed are not necessarily the views of the sponsors, the editors, or the individual working group chairmen. These proceedings are intended primarily to document the presentations and discussions that took place at this workshop, for the benefit of the engineering community at large.

ACKNOWLEDGEMENTS

A large number of people contributed to the successful outcome of the workshop. Most particularily this included the steering committee, which advised in setting up the program and identifying the working group topics :-

Steering Committee

A. Alvarado, Pipeline Unit, Minerals Management Service, New Orleans
J.G. Bomba, Kvaerner Earl and Wright Inc., R.J. Brown & Associates
W.C. Bertges, U.S. Dept. of Transportation, Louisiana
K.E. Breaux, Project Consulting Services, Metairie
L.J. Broussard, Tenneco Gas
J.P. Cordner, B.P. Exploration Inc.
C.L. Hebert, McDermott Inc.
M.G. Hinojosa, La. Dept. of Natural Resources
R.E. Hoepner, Transco Gas Pipeline Corp
J.E. Kohler, Pipeline Safety, Office of Conservation, Baton Rouge
J.R. Lehman, Trunkline Gas Company
G.E. Lochte, H.O. Mohr Research & Engineering
D.V. Morris, Texas A&M University
J.T. Robinson, Mobil Exploration & Producing
G.G. Schulte, Chevron Production Co.
C.E. Smith, Offshore Minerals Management, Minerals Management Service
J.C. Thomas, U.S. Dept. of Transportation, Houston
H. Wright, J.P. Kenny International
G.L. Zimmermann, Shell Oil Company

A large measure of credit for giving the meeting an initial picture of the main issues, belongs also to the keynote speakers, who devoted their time to an excellent series of presentations to the meeting :-

Keynote Speakers

Chris Oynes, Regional Director, Minerals Management Service, New Orleans
George Tenley, Office of Pipeline Safety, Dept. of Transportation, Washington
James Calhoun, Marine Safety, U.S. Coast Guard, New Orleans
Ray Smith, National Energy Board of Canada, Calgary, Canada
Dan Houser, McDermott Inc., Morgan City, La.
Roberto Bruschi, Snamprogetti, Fano, Italy
Michael Krogh, Dansk Olie og Naturgas, Horsholm, Denmark

Howard Wright, J.P. Kenny International, Houston, Tx.
Jay Mandke, consultant (formerly SW Research Institute), San Antonio, Tx.

Particular recognition must also be given to Charles Webster, discussion leader & Crisis Management Consultant, for the special workshop on "Partnering" - "Anatomy of Risk Managements Process", sponsored by Tenneco Gas with active audience participation !

Thanks are also due to the chairmen of the working groups, for overseeing the individual workshop sessions, for bringing introductory material and encouraging participation, and most importantly for documenting the findings of each working group. These proceedings are in large measure the results of their efforts :-

Working Group Chairmen

Gary Zimmerman	Shell Oil Co.
Mark Berman	AMOCO Corp.
Jim Lehman	Trunkline Gas Co.
Greg Schulte	Chevron USA
Phillip Myint	Chevron USA
Ron Hoepner	Transco Gas Pipeline
John Robinson	Mobil Exploration
Chuck Hebert	McDermott Inc.
Jim Cordner	BP Exploration
John Bomba	Kvaerner/R.J. Brown
Dave Rechenthin	Clean Gulf Associates

Many local people also contributed to the smooth running of the arrangements, including the staff of the New Orleans office of the Minerals Management Service, and the staff of the New Orleans Doubletree Hotel.

Last but not least, none of this would have happened without the participants, who made it all possible.

SUMMARY

On February 22, 23 and 24, 1995, an international workshop on damage to underwater pipelines was held at the Doubletree Hotel and Conference Center in downtown New Orleans. It was attended by experts from the petroleum and offshore industry, consulting firms, government agencies, and academic and research institutions. The purpose of the meeting was to discuss current practice, progress, and future directions in the field of safe management and design of underwater pipelines. Recent experiences and case studies were included.

Invited papers were presented by representatives of government agencies in the U.S. and Canada, from consulting engineers around the world, and from universities. Five working groups were then formed on topics previously identified as of special importance. These groups met for over a day in parallel sessions led by co-chairmen who were charged with leading discussion and recording the results. Participants were free to attend more than one session if desired. The final reports of each working group were subsequently prepared by the chairmen, and these form the central body of these proceedings. Among other topics the following key issues were identified :-

1. Regulatory Issues - including adequacy of regulations on surveying, depth of cover inspections, smart pigging etc; permitting & reporting requirements, GIS usage; agency jurisdiction & enforcement; abandoned pipelines; damage compensation; pending regulations

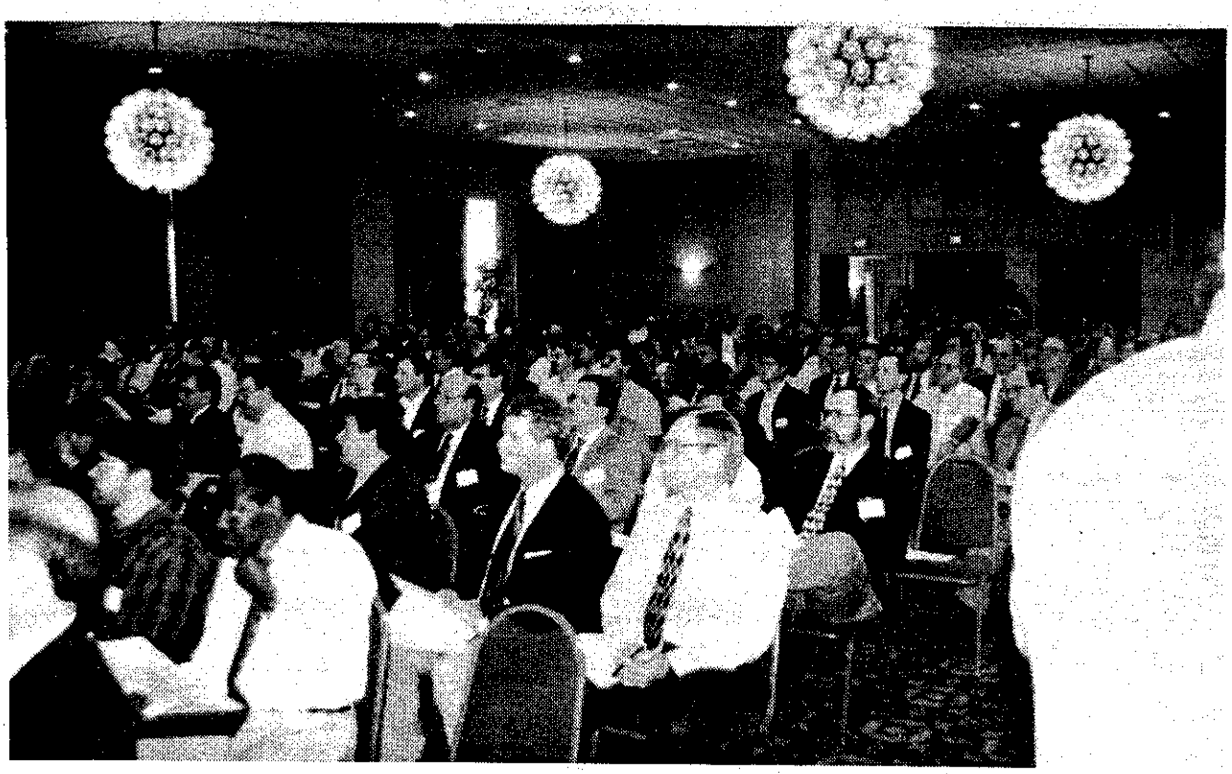
2. Operational & Other Damage - including internal & external corrosion; vessels, anchors, jack-ups & nets hitting & snagging pipelines; storm damage & inspection requirements; One Call feasibility for offshore

3. Reliability Design for New & Existing Pipelines - including overview of accident statistics; pipeline on-bottom stability; directional drilling design; dent research; breakaway fitting design; subsea valve guards; subsea pigging & retrieval; material & corrosion considerations; use of coil tubing as pipelines, stabilization of existing pipeline crossings

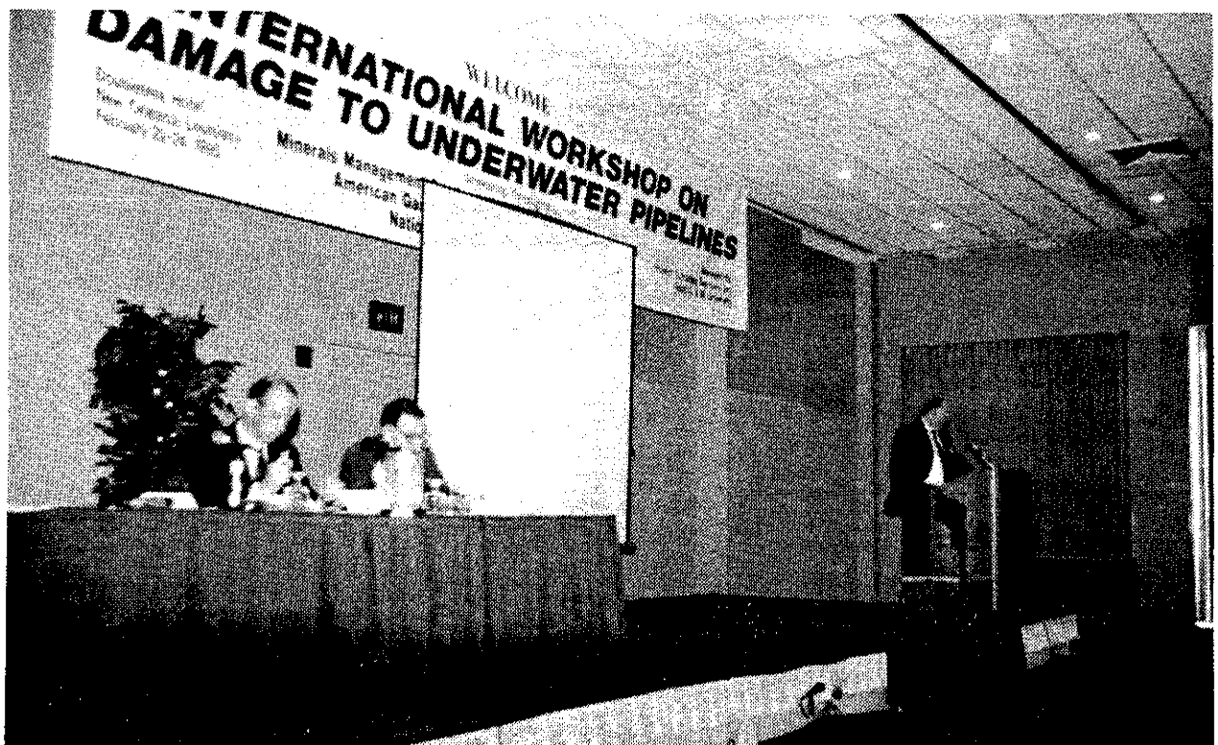
4. Repair Considerations - including damage & location survey; deep & shallow water repairs; flexible pipe repair; permanent vs temporary repairs; ROV & diver assisted repairs; project management considerations

5. Response to Abnormal Situations - including reporting response to situations; testing and shut-down; automated systems; pollution control, natural disasters such as approaching hurricanes and on-land flooding; training & mock emergencies

PHOTOGRAPHS OF THE MEETING

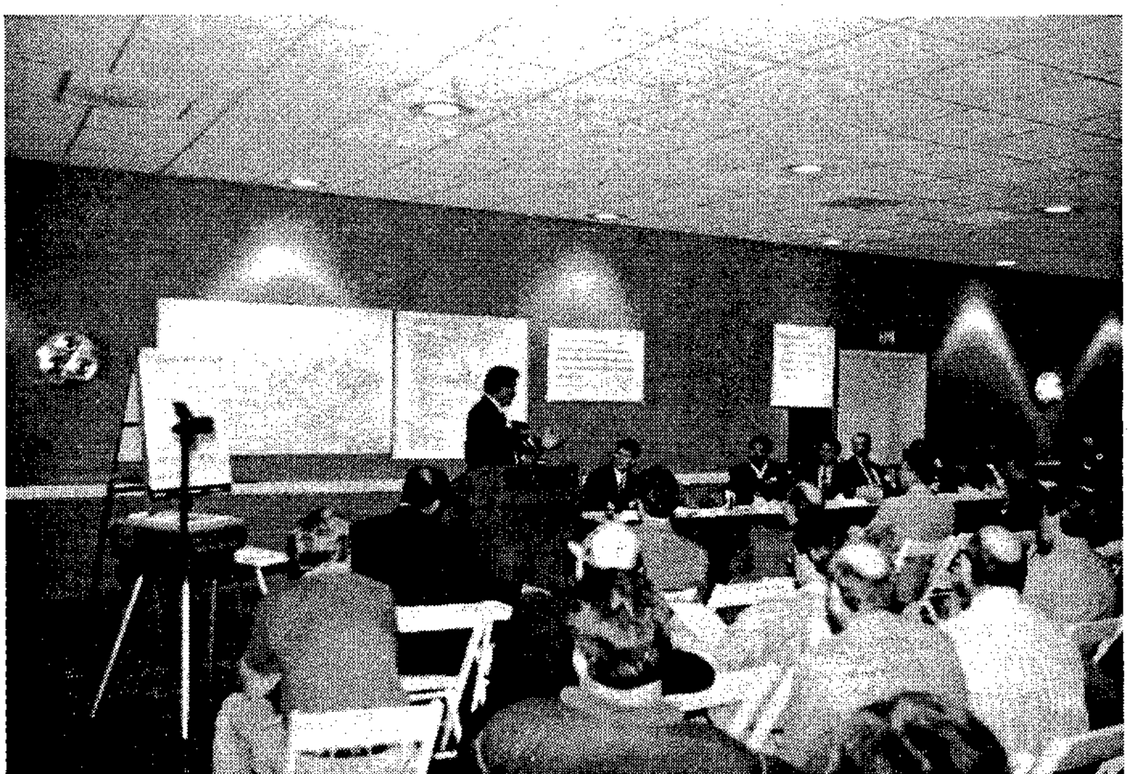


Participants Assembling to a Packed House of over 300 Registrants



The First Keynote Address Underway

Working Group 1 in Session



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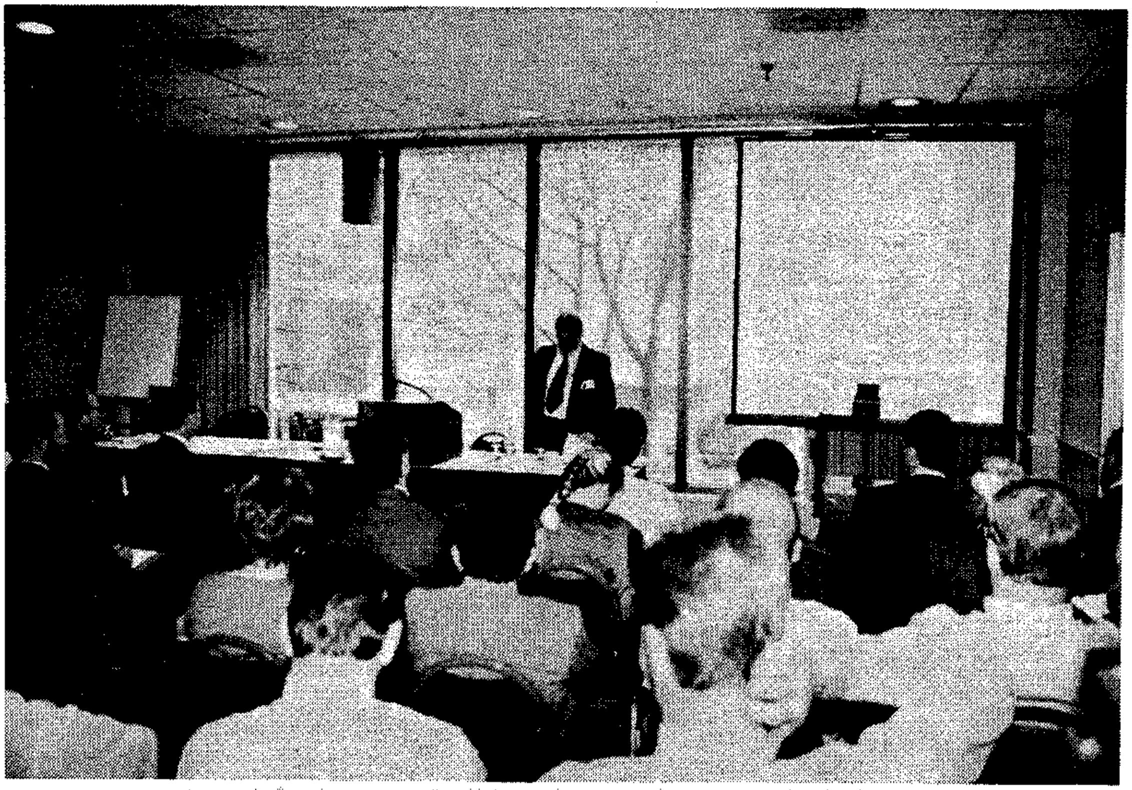

Working Group 5 Listening to a Presentation

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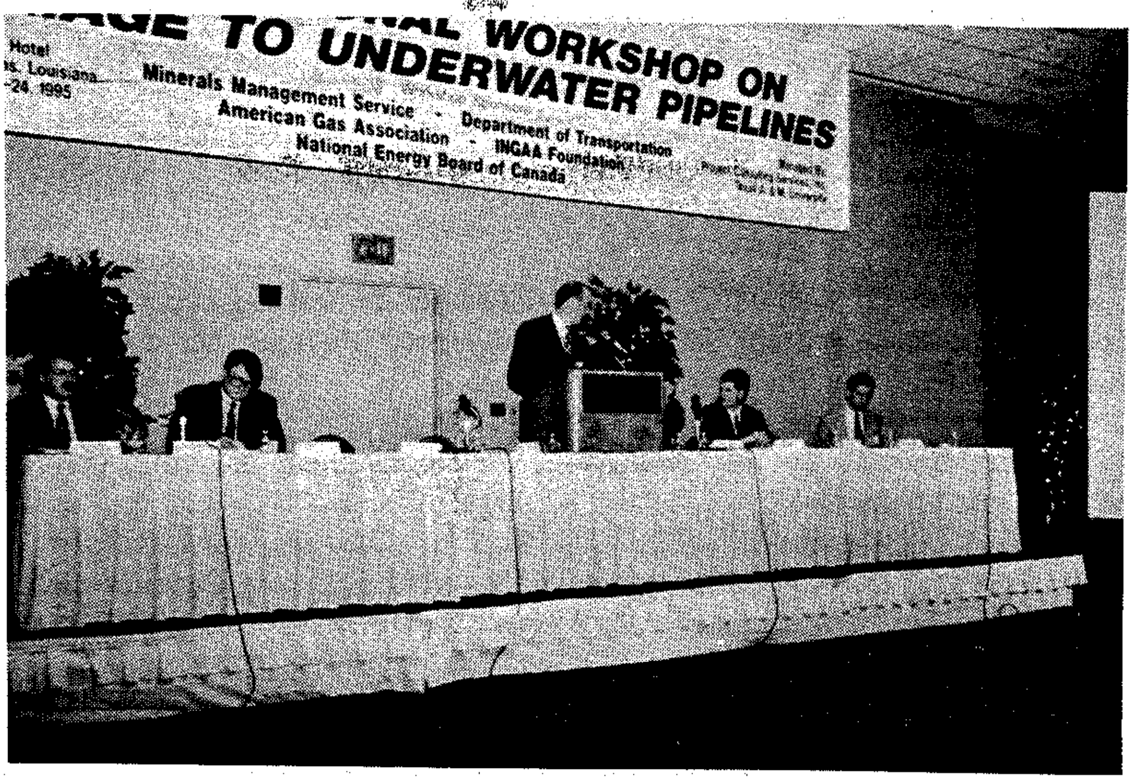
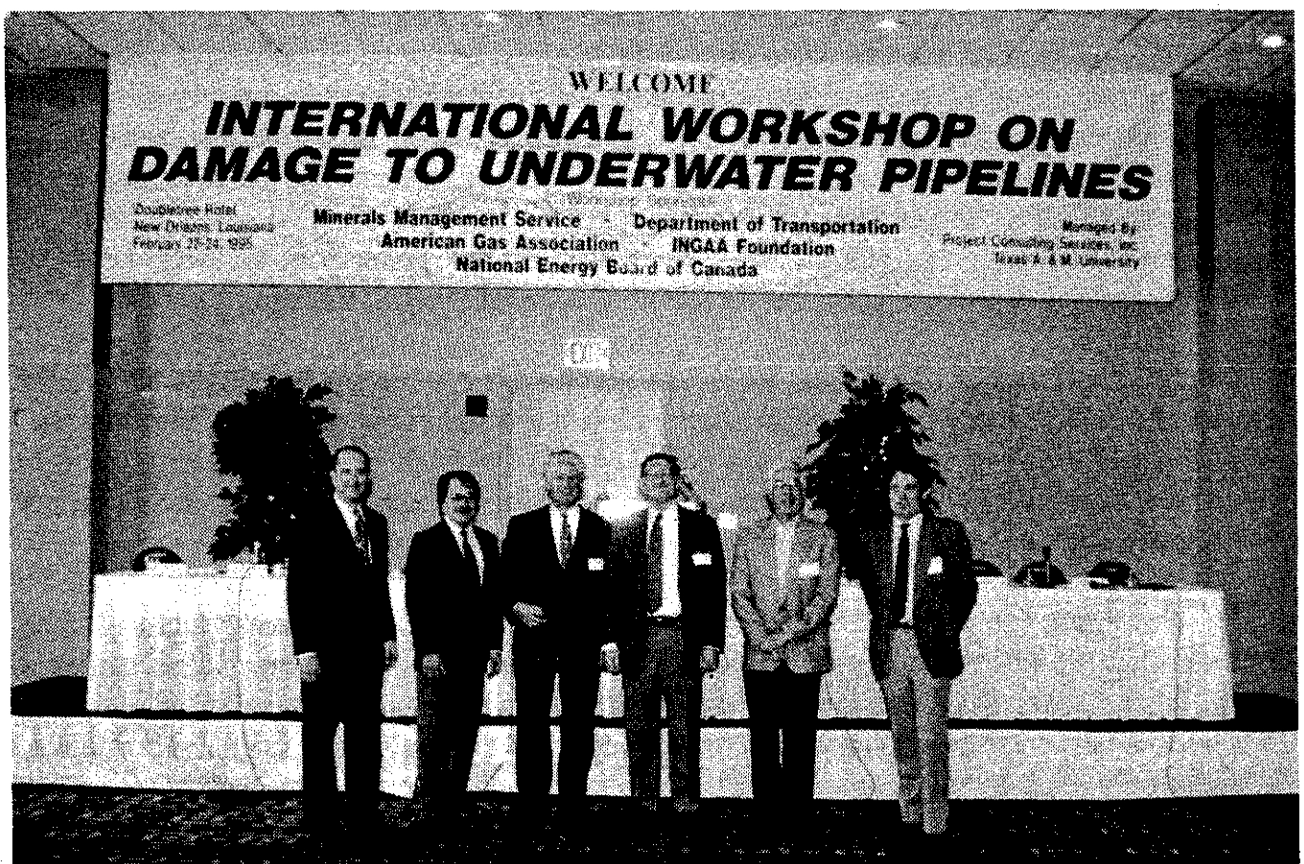


Final Summarizing and Comments



Some of the Organizers Gathering after the Meeting (from left Ken Breax, PCS Inc., Alex Alvarado, MMS New Orleans; Ray Smith, NEB Canada; Charles Smith, MMS Washington; Cesar Deleon, DOT Washington; Derek Morris, Texas A&M)

WELCOMING REMARKS

Welcome to "N'Awlins" ! - a rich blend of historic significance and future promise, New Orleans is a city of impressive diversity which has lured travelers from around the world for centuries.

Founded in 1718 by Jean-Baptiste LeMoyne, Sieur de Bienville, the city was named in honor of the Duke of Orleans, Regent of France. New Orleans became the capital of French Louisiana in 1723. The next 80 years saw New Orleans and the Louisiana Territory change hands repeatedly between French and Spanish rule. Then, in 1803, Napoleon sold the entire Louisiana Territory to the United States for $15,000,000.

In 1717, she was a mere flicker in the eyes of the French. A year later she was christened on the banks of a great river - a Creole princess born in the new Louisiana Territory. She lived among Choctaw and Chickasaw; explored dark shadowy bayous; lazed on sun-drench shores; and battled flood and disease. She knew swaggering pirates, and scarifying voodoo secrets. The Spaniards adorned her with architectural splendors, but her proud French creole origins were apparent everywhere. She warmly welcomed the fun-loving Cajuns who came in 1763, gifting her with incomparable zest. She discovered in herself a natural instinct for soul-stirring music; her cuisine was truly exotic. By the time she became an American citizen in 1803, she was quite famous, as Europeans flocked to her door. That little waif on the waterfront was named New Orleans, and she grew up to be the European Queen of the Mississippi.

New Orleans is like a rich, bubbling gumbo simmering on the stove. Its heady aroma and dark, savory beauty are created with just the right combination of ingredients - a heaping tablespoon of history, a dash of charm and a pinch of *joie de vivre* thrown in for good measure. The city's unique neighborhoods, each with its own distinct personality and sense of purpose, provide the perfect blend of spices.

For many years, New Orleans was a city of two peoples with distinct cultures. The French Creoles lived in their insulated French Quarter, while the Americans staked a claim in the areas beyond Canal Street. With the Louisiana Purchase in 1803, more Americans poured into the city and set out to develop the faubourgs, or neighborhoods, along St. Charles Avenue.

The French Quarter to Orleanians is "downtown" - to distinguish it from the areas across Canal Street which were "uptown" and were originally the districts first settled by the "Americans." The French Quarter or Vieux Carre (Old Square) was the original Franco-Spanish city of the Creoles. Today many prominent Orleanians reside in the French Quarter, occupying historic and beautiful old houses. The 'Quarter begins at Canal Street and extends to Esplanade and is bounded by Rampart and the Mississippi River. The 'Quarter is not just buildings and history - it is also a pleasant and aromatic perfume - of roasting coffee, of dockside bananas, of molasses from the praline shops, of whiskey from the pungent bars of Bourbon Street.

One of the neighborhoods carved from the Livaudais Plantation in 1832 was what has become known as the **Garden District.** This was where Americans built lavish homes in the 12-block area between St. Charles, Jackson and Louisiana avenues and Magazine Street.

The flagstaff in Jackson Square has witnessed the flags of France, of Spain, of the United States and of the Confederacy all hoisted and all hauled down. Orleanians , by reason of their long and colorful history, are sophisticated and inclined to be blase -they have seen much change and have endured it well. But let us begin from Canal Street on Royal Street, the elegant main thoroughfare of the old Franco-Spanish town which was Nouvelle Orleans in the early 18th century. Almost every building has been the scene of history.

While strolling through the bustling French Quarter, it is hard to imagine the lonely expanse of land that greeted Jean-Baptiste LeMoyne, sieur de Bienville, nearly three centuries ago. Then, unknown dangers lurked in the murky swamps that surrounded this fledgling settlement. Today, the Vieux Carré is home to fine restaurants, night spots, retail shops and attractions.

You can still see the symmetry of design employed by French engineers who planned the city in the early 1700's . Bordered by Canal and N. Rampart streets, Esplanade Avenue and the Mississippi River, its streets are of even width and length and form a grid pattern. At the center of most colonial outposts was a Catholic church, flanked by other important buildings, surrounding a *place d'armes* or parade ground. It is **St. Louis Cathedral, the Cabildo, Presbytere**, and **Pontalba Apartments** that encircle **Jackson Square**.

New Orleans has its share of famous streets. Bourbon, Basin and Rampart have all been immortalized in song. But the street that best captures New Orlean's neighborhood flavor is Magazine Street. Stretching six miles parallel to the river from Canal Street to Audubon Park, Magazine Street slices through many typical yet different parts of the city. The Warehouse District, the Irish Channel, the Garden District, and the Latin community are all traversed by Magazine Street. Along its route you can find some of New Orleans' best restaurants and most interesting retail shops.

A slow but steady interest in Magazine Street has resulted in a new look for an old street. It was named for the arsenal once located near Canal Street. Preservationists and businessmen have restored many of the old buildings that had lost some of their original charm through neglect. Many of the buildings in the Warehouse District have now been converted into desirable office space and apartments or condominiums.

Dining out in New Orleans is a joyous social event, not only for the visitor but for the New Orleanian as well. Delighted as the local restaurant is to cater to the tourist, the high standards of his kitchen are maintained by the critical tastes of the residents. And here, in America's European Masterpiece, the dining is done very much in the Continental style - which is to say, in an unhurried, leisurely manner. For us, food is not something to be gobbled down in a frantic race to get on to the next attraction. In New Orleans, food is one of the most important attractions. A meal is to be lingered over, commented on, savored, and remembered. In the words of Joe Cahn, Director of the New Orleans School of Cooking, "In South Louisiana, food is not looked upon as nourishment, but as a wonderful way of life. To us, food is not only on the plate; it is also in the heart."

Though New Orleans is synonymous with great food and jazz, during the last decade, it has added yet another facet to its colorful kaleidoscope - shopping meccas that epitomize the flavor of the city. Some project an air of sophistication; others resemble a buzzing festival market place. Most carry an eclectic mix of shopping opportunities, with prices that suit nearly every budget. Many of the merchants offer shipping around the country, and offer vouchers for tax-free shopping to international visitors.

However you should not confine your interests to downtown ! One of the most unique sights in New Orleans is its burial grounds. In early days, the city's high watertable made it virtually impossible to bury the dead below ground. New Orleanians opted to use the Spanish custom of above-ground burial. These cemeteries, with row after row of house-like tombs, have been called "cities of the dead."

Few places in America offer clearer evidence of the tie that exist between lifestyle and design than the plantation homes of the Old South. While delightfully individualistic, there are underlying similarities in these gracious manors that proclaim them as Southern. The hundred-mile stretch of road that winds along the banks of the Mississippi from Baton Rouge to New Orleans affords a rare opportunity to see and experience the Southern way of life. While driving historic River Road, catch glimpses of beautiful countryside and plantation homes.

Watching a massive tanker navigate the sharp, crescent-shaped bend in the Mississippi River, one is reminded of how this waterway - and the ships that cruise it - have influenced the development and identity of New Orleans. During the golden age of steam boating between 1820-1870, pleasure and profit were married in the powerful stern wheelers that transported cotton from plantations upriver to auction houses in New Orleans. The economy was booming, thanks to King Cotton, and many Louisianians were getting rich. Steamboat operators soon realized that by refurbishing their vessels they could attract these affluent travelers as passengers on their regular routes. These floating palaces became more and more opulent, with amenities such as carved mahogany bars and crystal chandeliers.

Riverboats have remained a fixture in New Orleans. Scenic cruises have always been popular, and now that gambling has returned, there are more people than ever discovering pleasure and profit on the Mississippi's famous muddy waters. New Orleans has much to offer, much to do and see - all offered in a manner uniquely her own.

When the sun sinks, the curtain goes up on one of the most unforgettable shows in all the world. New Orleans at night! Go gently into your night in a romantic horse-drawn carriage. Dine in fabulous restaurants . . . dream along the River on a dinner-jazz steamboat cruise. Later, follow the action on Bourbon Street where you will find a carnival of barkers, cabarets, Sazeracs, Hurricanes and any number of restaurants.

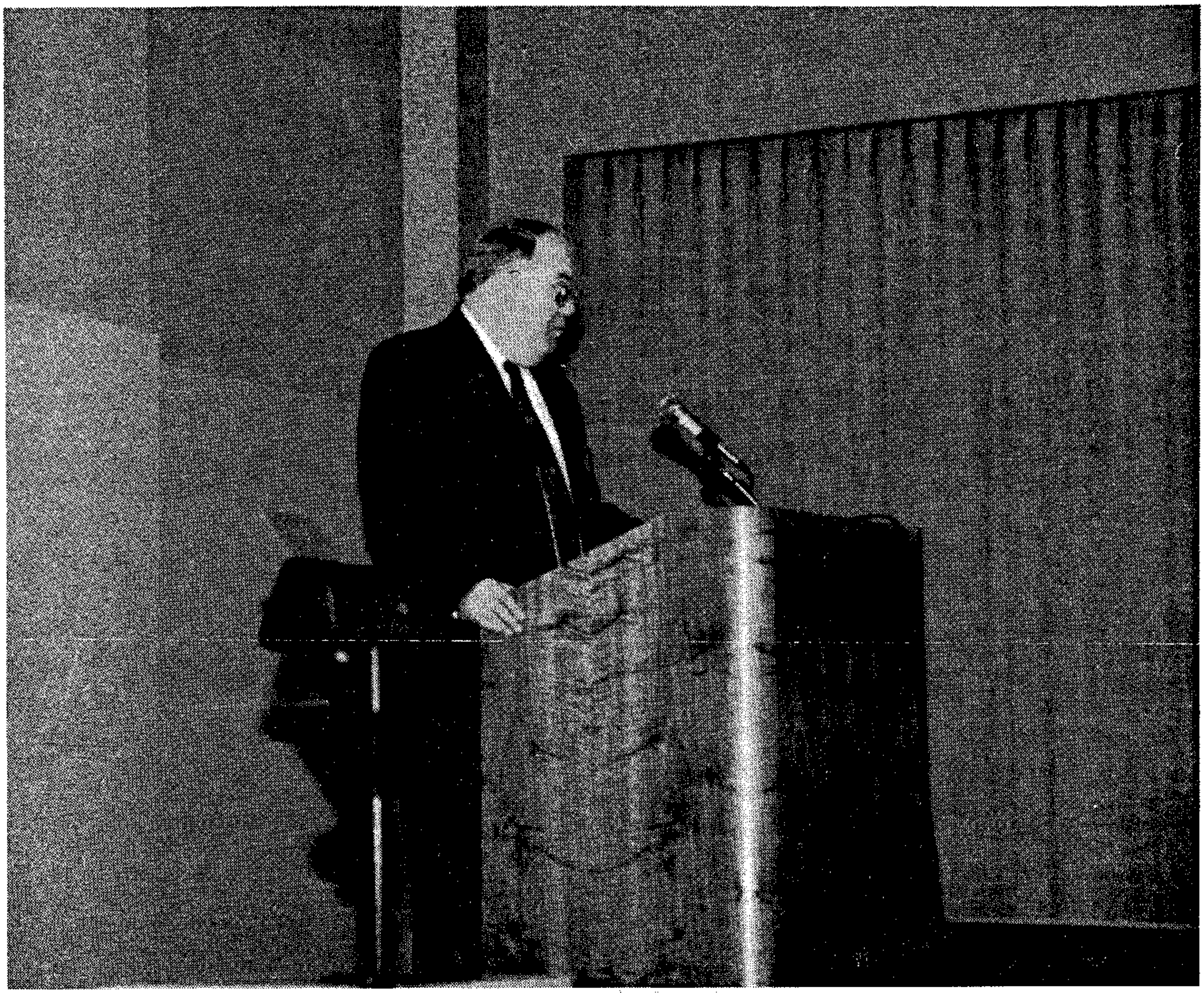
Nightlife moves to the finger-snapping, top-tapping, intoxicating sounds of Dixieland jazz. See a show or a concert at one of New Orleans' modern theatres. The Theatre of Performing Arts, home for our outstanding opera and ballet companies. The Orpheum Theatre is the home of the Louisiana Philharmonic Orchestra and the Saenger Theatre offers Broadway shows and celebrity entertainers.

Boogie till dawn, stomp to a Cajun beat, or dance cheek to cheek in an intimate night club. All through the night and into the wee hours, New Orleans buzzes with excitement.

Enjoy your stay - you'll love New Orleans and she'll love you right back !

KEYNOTE ADDRESS I

Chris Oynes
Regional Director
Minerals Management Service
Department of the Interior



Introduction

It is with enthusiasm that the Minerals Management Service (M.M.S.) has participated in this workshop, which has been co-sponsored by a number of major organisations in this area, including the Minerals Management Service, the Office of Pipeline Safety, the American Gas Association, the Interstate Gas Association of America, and the National Energy Board of Canada. A steering committee made up of representatives from industry, state and federal government, service companies, was responsible for planning the overall format, and the detailed management was conducted by Project Consulting Services, inc., in association with Texas A&M University.

One of the motivations in participating in this event, is the desire that this workshop will provide an opportunity for professionals with an interest or regulatory responsibility over offshore pipelines to share ideas, identify and discuss issues of mutual concern, and agree on possible solutions and directions.

Why are we here? We are all concerned with safety issues regarding marine pipelines. The Marine Board's committee, in 1994, issued a report on improving the safety of marine pipelines. It eloquently summarized the concern with the following words:

"The safety of the United States' undersea pipeline systems, in terms of both human safety and potential for environmental damage, is a major national concern. These systems, in federal and state waters in the Gulf of Mexico and off Southern California and Alaska, extend more than 20,000 miles, carrying almost one-fourth of the nation's natural gas production and more than one-ninth of its crude oil.

"Several accidents in the late 1980s, which claimed more than a dozen lives, raised public and congressional concern about the safety of the subsea pipeline system. This system must coexist with some of the world's busiest ports and most productive fisheries. Its structural integrity and maintenance are also subject to question, for much of it was installed in the 1940s and 1950s. Both maritime accidents and pipeline structural failures could result in pollution of fishing areas and coastal lands."

Background

Before we discuss some of the general topics that will be addressed during the workshop, I would like to provide a brief overview of the Minerals Management Service's role with offshore pipelines. The primary responsibility of the MMS is to ensure that all aspects of oil and gas exploration, development and production, transportation, and abandonment activities on the Outer Continental Shelf are conducted in a safe and environmentally sound manner. The MMS jurisdiction extends seaward from the offshore federal/state boundary, and the pipeline jurisdiction is shared with the Office of Pipeline Safety. Presently, there are over 21,000 miles (34,000 kilometers) of approved pipelines in the Gulf of Mexico, 34 percent of which have been in service for more than 20 years, the minimum design life of OCS pipelines. 1994 was an especially active year for pipelines, as far as the MMS was concerned, with over 325 segments approved, involving over 1,200 miles (1,900 kilometers). Indications are that 1995 may be even more prolific. Presently, oil and gas companies in the Gulf of Mexico produce over 300 million barrels of oil per year and almost 5 trillion cubic feet of gas per year.

Topics

I would like to highlight a few topics that are of particular interest to the MMS. These include: the report by the Marine Board on Pipeline Safety, the draft Memorandum of Understanding between the Department of the Interior and the Department of Transportation regarding offshore pipelines, impacts of Hurricane Andrew, and what future activities are needed, including research.

First of all, the Marine Board report. The committee on the safety of marine pipelines under the auspices of the Marine Board of the National Research Council issued a report in 1994, entitled "Improving the Safety of Marine Pipelines." This project was co-sponsored by the MMS and the Office of Pipeline Safety. The report addressed issues regarding damage to offshore pipelines and made recommendations on other aspects of pipeline operations including smart pigging, leak detection, and corrosion.

The MMS realizes that using smart pigs offshore is presently limited, but encourages the further development of such devices to detect anomalies which could lead to pipeline failures. The MMS Gulf of Mexico OCS regional office is presently considering requiring the use of smart pigs in cases where it is feasible and cost effective.

Another aspect of pipeline operations addressed by the marine board report was the area of leak detection. The MMS encourages the broader use of automatic line balance control systems to provide quick detection of relatively large leaks.

MMS recognizes that the majority of all offshore pipeline leaks are caused by corrosion. Possible improvements to this situation might include requiring routine inspections of pipeline risers where most of these leaks occur and/or setting standards for corrosion protection.

The Marine Board report noted that: "the lack of consistent and comprehensive data on the safety record of offshore pipelines is a severe challenge for safety planning" (page 33). This is an area that needs additional work.

In general, all of the above areas are worthy of additional discussion.

A second topic is the revised Memorandum of Understanding (MOU). A revision to the MOU on offshore pipelines between the Department of the Interior and the Department of Transportation has been drafted, and will be a topic of discussion during this workshop. This revision will soon be published in the Federal Register for comment, but we thought it would be advantageous to provide the opportunity for its review during the workshop. The intent of the MOU revision is to redefine the boundary lines over which MMS and OPS exercise their respective jurisdictions and provide more efficient utilization of government resources.

A third topic that is of interest to MMS is Hurricane Andrew damage. Hurricane Andrew caused extensive damage to some offshore pipelines. This topic will be discussed throughout the workshop and many details will also be provided in Mr. Warren Williamson's paper. It is hoped that we can use this recent experience to enhance the ability to prepare for and cope with these types of abnormal situations. Although impact to the environment from pipeline failures during the hurricane was minimal, we believe there is still room for improvement.

A fourth and last area is that future work is necessary and underway.

The MMS provides funding for workshops of this type and research projects under our technical assessment and research program. The research program seeks to enhance an understanding of the constraints on offshore operations especially as they relate to prevention of pollution, integrity of structures and pipelines, and technologies necessary to cleanup oil spills. Research projects, both ongoing and proposed, include:

- an evaluation of Hurricane Andrew pipeline damage;
- an assessment on the performance of safety equipment during Hurricane Andrew;
- a study of available and new technologies for leak detection;
- development of a risk-based methodology for decision making regarding pipeline integrity and maintenance; and last,
- an investigation on securing MODU's during storms.

We encourage your suggestions on what other areas of research are needed.

Conclusion

All of you are actively involved in encouraging the development of improvements to the safety systems and pollution prevention methods for offshore pipelines.

I am confident that the attendees of this workshop, working together, will take this opportunity to generate ideas and develop recommendations to provide valuable feedback to both industry and government. I again want to thank the sponsors and organizers for making this workshop possible.

KEYNOTE ADDRESS II

George W. Tenley, Jr.
Associate Administrator for Pipeline Safety
U.S. Department of Transportation
Washington, D.C.

As the events of November 8th of this year has made clear, politics, government, and business have entered an era of change unparallelled in this generation. For the pipeline safety community, the following changes are worth mentioning:

- Pipeline safety is now recognized within the Department of Transportation as a critical public policy issue, about which the Secretary of Transportation is deeply interested.

- Pipelines are correctly being seen as a mode of transportation, and are included in the Secretary's National Transportation System Initiative.

- The Secretary successfully achieved a doubling of the pipeline safety budget in fiscal year 1995 to build the capability for the pipeline safety program to fulfill his vision for pipeline safety.

- That vision may be summed up as making the pipeline safety program a mature program with the technical competence and knowledge to enable it to be a credible and independent assessor of the quality of the infrastructure.

- We are in a reauthorization year, dealing with a dramatically different Congress, pursuing a dramatically different agenda. The goal for all of us should be to seize the opportunity the new Congress provides, to deal with our issues in new ways.

- Finally, all segments of the pipeline industry are looking more closely than ever at the economic challenges and opportunities they face, including the issue of who pays for pipeline safety, how much, and through what means.

The issue for the executive branch, Congress, and the pipeline industry, is how will this change be directed and managed, so that we can shed what doesn't work, and seize the opportunities to assure that this critical infrastructure is sound, and that the American people understand what we do and why.

As a federal regulator, I have come to the conclusion that the traditional pipeline safety paradigm of command and control regulations must give way to a risk managed pipeline system, where doing the right thing is something different than merely complying with minimum safety standards. As we know, changing a paradigm can be a daunting task because you must change the way people believe, think, and act.

The principal challenges in changing the pipeline safety paradigm from regulatory command and control to risk management are:

- firstly the poor credibility of both the industry and government with the public, typically the public facing the aftermath of a catastrophic accident.

- secondly the erroneous, but time-worn negative yardstick of pipeline safety, namely the number of deaths and injuries, enforcement cases brought, and penalties collected, and

- thirdly the widespread, but erroneous, belief that the pipeline industry has unlimited resources to make the pipeline infrastructure risk free.

What will it take to meet these challenges, and change the paradigm? It will take political will, creative thinking, effective partnerships, and, as much as anything else, trust.

I believe that the vehicle for this change is the concept of risk management. In the realm of pipeline transportation, there are at least 5 clear benefits that derive from a risk management approach. Risk management

- acknowledges the unique nature of pipeline systems and pipeline segments; enables the break from "one-size-fits-all" regulations.

- puts more pipeline safety decision-making in the hands of the experts, namely the pipeline industry.

- allows available resources to be applied to actions that provide the greatest impact on risk reduction.

- frees industry and government of the "compliance with minimum safety standards" mindset as the way to judge whether operators are making the best decisions, and

- enables government to judge industry performance based on positive performance measures.

Under a risk management approach, the goal for the pipeline industry and government should be to create a standard of quality wherein each operator uses the best means to meet risk assessment standards that define the standard of quality.

This positive measure of performance will give a true picture of the infrastructure, including both the risks and the means by which those risks are being controlled. This will provide an alternative to statistically insignificant negative performance measures and set a course for pipeline safety that is charted by the industry and government working in partnership.

In a restructured Department of Transportation, positive performance measures will foster a mission that appropriately recognizes that safety is not an end in itself but a critical means to an end - namely, the efficient and economically sound transportation of energy.

With an accurate and defensible picture of the quality of the infrastructure, we will have a story to tell Congress and all Americans that will improve the "environment" in which we will be achieving pipeline safety in the future. This increase in public awareness and information is a necessary precursor to improved trust.

Within my agency, the Research and Special Programs Administration, we have already begun to create the new paradigm of risk management. I would like to briefly mention critical initiatives that we have under way:

- Firstly we have created partnerships with the pipeline industry, and federal, state and local governments to develop the foundation for risk management criteria for pipeline transportation. This work will be the foundation for a regulatory system that acknowledges that

a) each pipeline system is unique;
b) each risk does not pose the same probability of occurrence and consequence; and,
c) given the right tools and the maximum technical discretion possible, the pipeline industry will do what is right to preserve these vital economic lifelines.

- Secondly we have created a multi-interest, multi-discipline team to develop the basic elements of a national mapping program.

- Thirdly we are building a risk assessment program for how we in the Office of Pipeline Safety determine the relative ranking of the risk issues we face, the solutions for those risks, the cost of any solution, and our response to those risks in the order of the relative magnitude of the threats they pose to public safety and the environment.

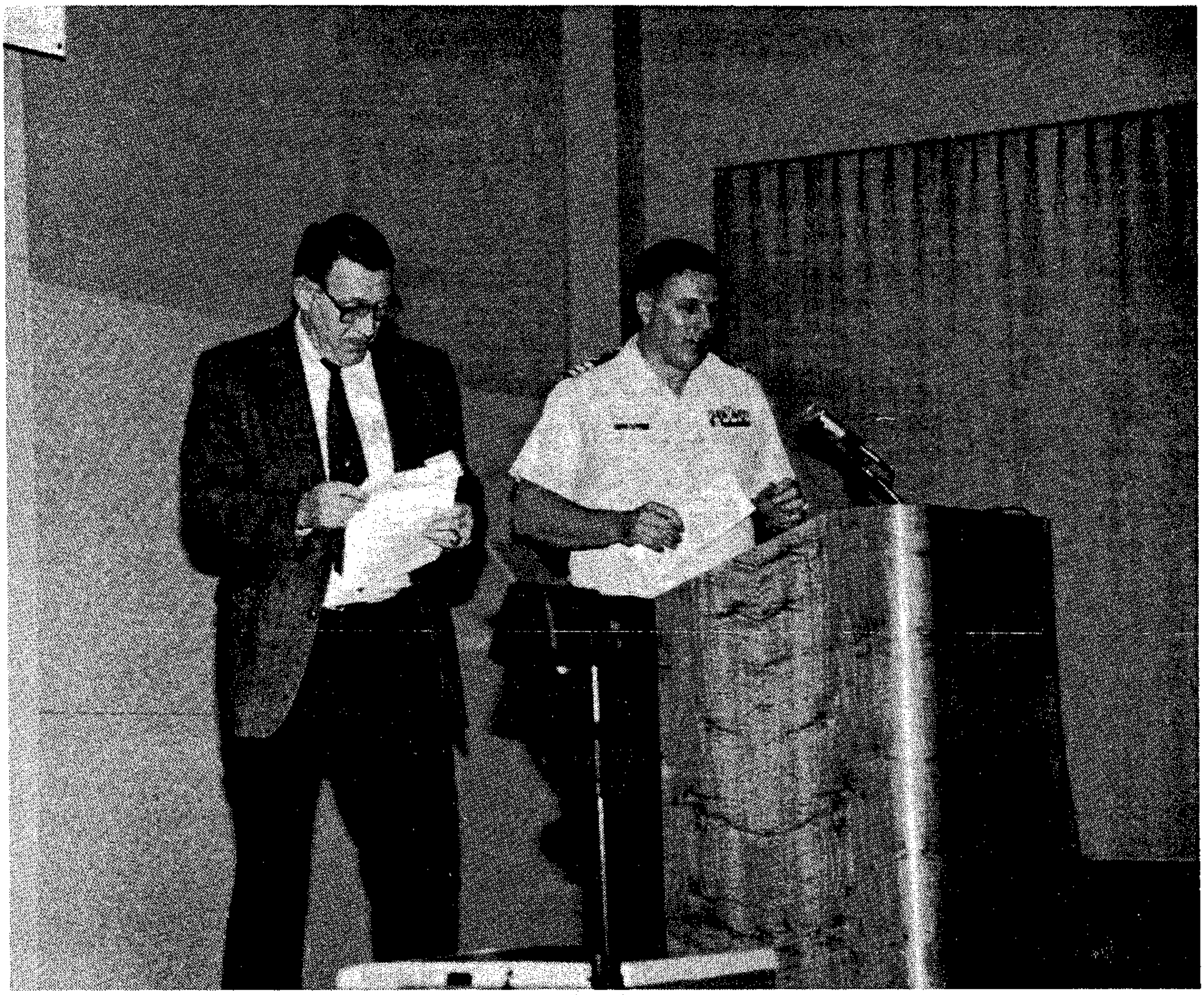
- Fourthly we are working with the pipeline industry to develop a collaborative research agenda for pipeline safety. This critically important research agenda and the products it will produce are the foundation for the transformation to a risk management paradigm.

- Fifthly in our reauthorization bill that we will send to Congress shortly, we will seek a risk management framework in the law that will enable Congress to direct us to examine issues of interest to them, while reserving to the Department the discretion to determine how best to address those issues. This approach is predicated on the idea that a regulation is not needed in all cases, and not all pipelines and pipeline segments need to be regulated in the same way. This office helped to devise, and will participate in, this afternoon's scenario exercise to explore the use of risk management principles for making critical pipeline business and operating decisions. I believe the exercise will demonstrate one of the critical aspects of risk management - that it is a way of doing business that transcends all levels and actions of a pipeline company.

In conclusion, taking these initiatives together, I am very excited at the prospect of ongoing partnerships with the industry, all levels of government, and the public to develop and deploy a new policy and decision framework that will assure that we do the right thing, for the right reason, with the right tools, and at the most economical cost consistent with public safety and a sound environment. This will contribute directly to the creation, application, and continual evaluation of the standard of quality I referred to previously.

KEYNOTE ADDRESS III

James Calhoun
Eighth Coast Guard District
United States Coast Guard Auxiliary
New Orleans, La.



Introduction

The activities and mission of the U.S. coast guard auxiliary is carried out in this part of the country by the Eighth Coast Guard District, often called the Guardians of the Gulf.

By way of introduction, the territory assigned to the Eighth Coast Guard District, headquartered in New Orleans, Louisiana, covers some 1,200 miles of coastline and 2,100 miles of inland waterways from St. Marks, Florida, to Brownsville, Texas — roughly one-half the Gulf of Mexico. There are approximately 3,024 active duty, 700 reserve, 200 civilian and 1,950 auxiliary personnel serving in the district. Each year the district carries out over 4,900 search and rescue cases, maintains 5,100 aids to navigation and responds to 4,100 pollution incidents in the Gulf of Mexico and inland waterways.

Organization

The district comprises four groups, three air stations, two bases, seven marine safety offices and three marine safety detachments. Besides these commands, there are 14 small boat stations, 14 aids to navigation teams, two vessel traffic services, one reserve training center, two reserve groups and 21 reserve units. The district also serves as the home for thirteen patrol boats and 11 buoy tenders.

Also found within the district, but outside the district's operational control, are the Aviation Training Center, Gulf Strike Team, National Data Buoy Center, Fire and Safety Test Detachment, two medium endurance cutters, a support center, a communications station and four Loran stations.

History

To put the current operation into perspective, there has been a Coast Guard presence in the Gulf region for almost as long as there has been a Coast Guard. One of the earliest recorded Coast Guard operations in this area involved the Revenue Marine Service cutter LOUISIANA during the Battle of New Orleans (in the War of 1812). On December 23, 1814, the LOUISIANA and the U.S. Navy vessel CAROLINA were given the task of driving the British away from the Mississippi River levee area below Chalmette, Louisiana. These two vessels carried out their tasks by bombarding the bivouac area of the British Army. A few days later the British destroyed the CAROLINA, leaving the LOUISIANA as the only naval vessel at New Orleans. As the British advanced on foot toward Chalmette, the LOUISIANA provided gunfire support for American forces until General Jackson's victory on January 8, 1815.

After the War of 1812, the Revenue Marine Service (as the predecessor of the modern Coast Guard was then called) focussed its attention on fighting slavers and pirates in the Gulf. On August 31, 1819, the cutters LOUISIANA and ALABAMA were fired upon by the privateer schooner BRAVO, after the ALABAMA's commanding officer tried to hail it near the Seventh-Eighth Coast Guard District boundary. The ALABAMA returned fire and quickly discovered that BRAVO was crewed by pirates. At the time of the battle, the pirates were attempting to escort home their captured prize, the Spanish schooner FILOMENA. Hostages aboard the FILOMENA were released and their pirate captors were imprisoned in New Orleans. Shortly thereafter, on April 19, 1820, the LOUISIANA and ALABAMA landed 25 well-armed men on Breton Island, Louisiana, to "neutralize" a major pirate stronghold. Although no pirates were found, the island was put to the torch.

During the Mexican-American War, Revenue Marine Service cutters blockaded Mexican ports and delivered war supplies to American troops in Mexico. The most notable shipboard delivery involved one thousand rifles aboard the cutters LEGARE and EWING. These rifles were delivered to General Taylor just before the decisive battles of Monterey and Buena Vista.

During the Civil War, one dry-docked and three floating Revenue Marine Service (RMS) district cutters were seized by Confederate forces. In a desperate attempt to prevent one of the four RMS cutters (RMS McCLELLAND) from falling into enemy hands, Treasury Secretary John A. Dix ordered "if anyone attempts to haul down the American flag, shoot him on the spot." His order became a rallying cry for the North.

In 1905, 40 years after the Civil War, the Revenue Cutter Service assisted the Public Health Service in enforcing a quarantine on ships entering and leaving New Orleans during a yellow fever epidemic. Six Revenue cutters and seven chartered ships boarded some 1,500 vessels and fumigated and/or quarantined 250 ships during the outbreak.

Thirty-seven years later, during the summer of 1942, the Coast Guard patrolled the Gulf searching for German U-boats. Post World War II records indicate that eight U-boats were operating in the Gulf of Mexico. Between May and June of 1942, 24 Allied vessels were attacked and 12 were sunk in the Gulf. The Coast Guard quickly organized the Auxiliary Coastal Patrol and Coast Guard Reserve force to combat the submarine menace. These forces sank one U-boat off southern Louisiana on August 1, 1942, and drove off the remaining German vessels.

Today's Mission

The role of the modern Coast Guard is as important now as it was in the early days of this country. Today's Coast Guard personnel are conducting missions of equal importance along America's southern coastline. They are interdicting drugs off the Texas-Mexico border, enforcing fishing regulations off the Florida panhandle, maintaining aids to navigation on the Mississippi River and responding to such natural and man-made disasters as hurricanes, pipeline and tanker spills in the Gulf of Mexico and Intracoastal Waterway. It is in this latter capacity that we are pleased to participate in this workshop on underwater pipeline safety.

Like their predecessors, the people of the Eighth Coast Guard District are working hard to maintain their title of ..."Guardians of the Gulf."

KEYNOTE ADDRESS IV

Raymond J. Smith
Engineering Branch
National Energy Board
Calgary, Canada

Introduction

It is a pleasure to be present at this workshop on behalf of the National Energy Board of Canada. The pipeline activities of the National Energy Board (N.E.B.) are the responsibility of the Engineering Branch, which is headquartered in Calgary, Alberta, and is charged with all aspects of pipeline safety, engineering, and regulatory oversight.

As a general introduction to the terms of reference, the National Energy Board is an independent federal regulatory tribunal, established in 1959. The Board reports to Parliament through the federal Ministry of Natural Resources Canada.

The Board currently consists of seven permanent Members, who are supported by a staff of just over 300 employees. The Board's regulatory powers are derived under :

- the National Energy Board Act;
- the Northern Pipeline Act;
- the Energy Administration Act;
- the Canada Oil and Gas Operations Act;
- the Canada Petroleum Resources Act; and
- the Canadian Environmental Assessment Act.

Its mission, as defined by Parliament, is to promote Canada's present and future interests in the development, distribution, and use of Canadian energy resources.

Organisation of the NEB

The organisation of the Board is such that it is now composed of 8 branches, each with distinct terms of reference, as follows:

- Economics
- Financial
- Energy Commodities
- Engineering
- Energy Resources
- Environment
- General Counsel and Law
- Personnel, Finance, Administration & Information Technology

By mandate, the NEB is required to regulate more than just pipeline activities, and is responsible for supervising a much wider range of activities in the energy sector. Its responsibilities, as far as Canadian industry is concerned, are defined as including the following areas:

- Frontier Development of Oil and Gas
- Pipelines
- Power Lines
- Energy Trade

In the area of pipelines, the Board regulates 59 pipeline companies of which 10 operate major pipeline systems. This includes in excess of 37,800 kilometers of pipeline; approximately 150 pumping and compressor stations; 18 tank farms; and 9 gas plants. Figure 1 shows the extent of the major oil pipelines in Canada, followed by the major gas pipelines in Figure 2.

Specific items that the NEB does not regulate, are:

- Intra-Provincial Facilities
- Energy Prices
- Provincial Energy Industries
- Coal, Uranium, Nuclear Power

Engineering Branch of NEB

The engineering functions of the Board is handled by the Engineering Branch. This is now composed of 6 divisions, which are currently constituted as follows:

- Development Engineering and Group II Pipelines
- Safety Audit, Monitoring and Enforcement
- Accident Investigation
- Pipeline Division A
- Pipeline Division B
- Regulatory Development and Safety Studies

The mission statement has been defined as follows:
"To serve Canadian energy interests by providing timely, high quality engineering and regulatory advice to the Board, to the Chief Conservation Officer and to the Chief Safety Officer."

Pipeline Activities

The Engineering Branch is constantly involved in many areas of pipeline activities. It is the lead Branch of the NEB in the regulation of the construction operation and abandonment of international and interprovincial pipelines in Canada. It also assists the Financial Regulation Branch in the Regulation of tolls and tariffs for oil and gas pipelines.
As far as frontier oil and gas activities are concerned, the Engineering Branch:

- is the lead Branch in the regulation of oil and gas exploration, development and production activities on Canada's frontier lands, excluding those areas offshore of Newfoundland and Labrador, and offshore of Nova Scotia which are subject to federal-provincial accords.

- regulates these activities to enhance worker safety, to protect the environment and to conserve oil and gas resources.

- is responsible for the provision of technical and engineering advice to the Newfoundland and Nova Scotia Offshore Petroleum Boards and to the other Federal Government departments.

Figure 3 shows the delineation of responsibilities for frontier oil and gas activities.

Regulatory and Legislative Activities

Under the provision of the appropriate legislative acts, the Board is responsible for administrating the following regulatory activities within Canada:

- Pipeline Regulations:
  - Onshore
  - Crossing
  - Offshore (Draft)

- Frontier Oil and Gas Regulations:
  - Drilling
  - Production and Conservation
  - Installations
  - Diving
  - Certificate of Fitness
  - Geophysical

- Codes, Standards, Recommended Practices, etc.
  - CSA (Canadian Standards Association)
    - Codes
    - Standards
    - Specifications
  - Canadian General Standards Board
    - Standards
  - American Petroleum Institute (API)
    - Recommended Practices
    - Specifications
    - Bulletins
  - National Association of Corrosion Engineers (NACE)
    - Standards

- Institute of Electrical and Electronics Engineers (IEEE)
    - Recommended Practices
- American Society of Mechanical Engineers (ASME)
    - Codes
- Det Norske Veritas
    - Rules
    - Guidelines

Principles of Canadian Pipeline Safety Requirements

As far as the overall philosophy of safety is concerned, the Branch has made a point of endeavoring to emphasize the following general principles in regard to Canadian pipeline safety requirements:

- Adopt CSA Standards
- Use a risk-based approach
- Develop cost benefit analysis/publicly accessible rationale
- Place burden of enforcement on regulated companies
- Avoid duplication of regulations, etc.

These general principles are designed to assist industry, while at the same time safeguarding the public and the environment.

We look forward to participating in this workshop, and to studying the recommendations resulting from it.

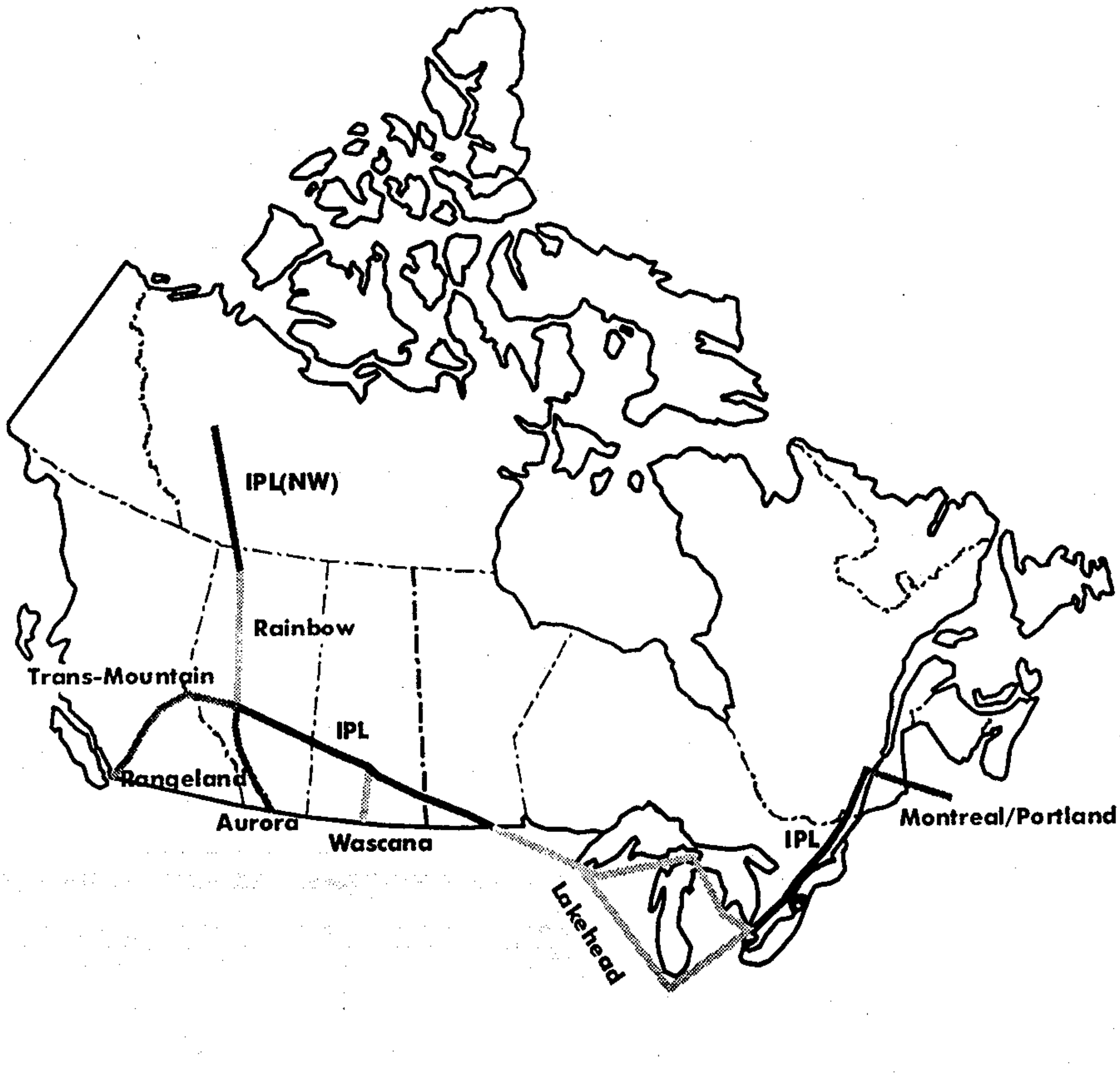


Figure 1 - Major Oil Pipelines in Canada

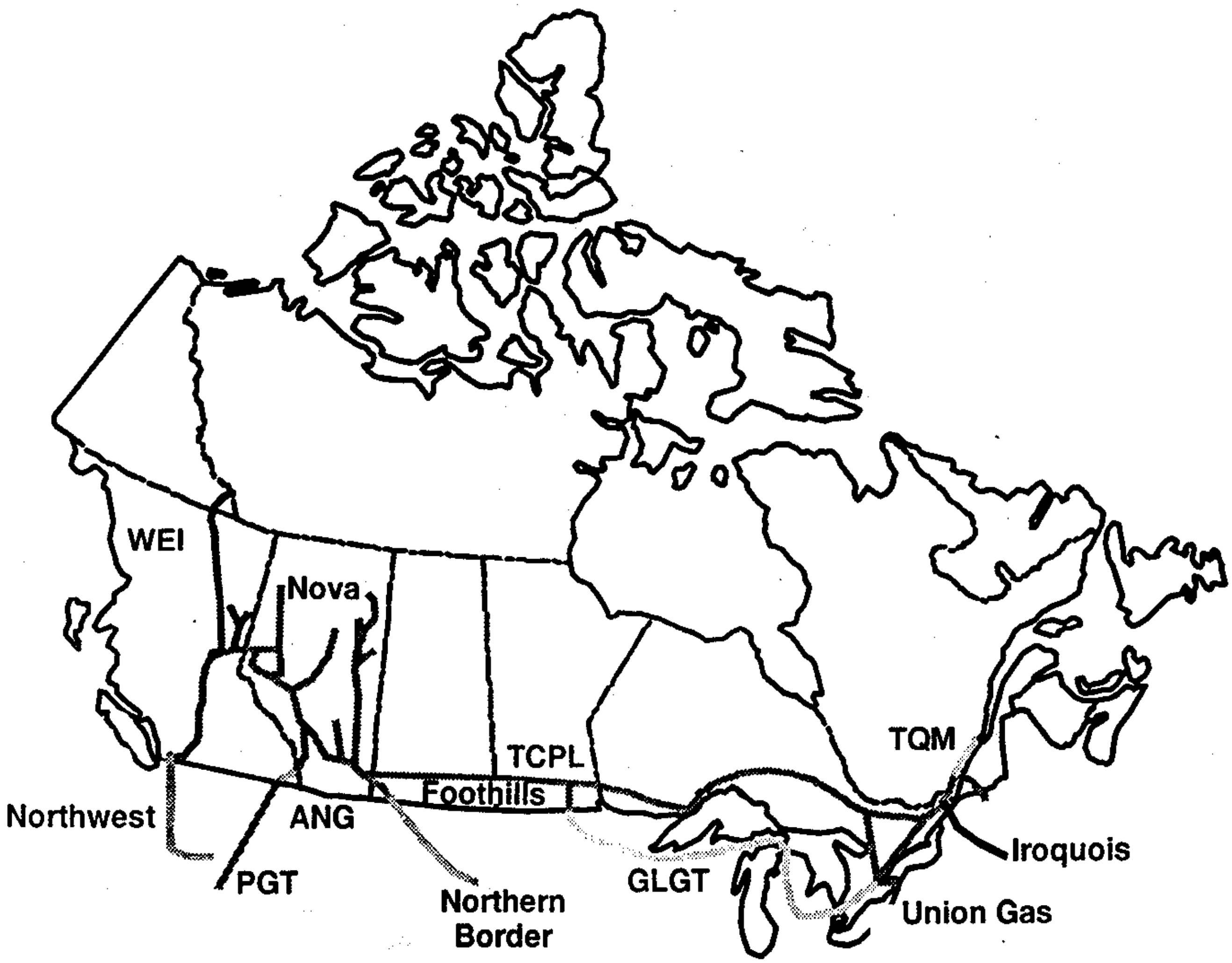


Figure 2 - Major Gas Pipelines in Canada

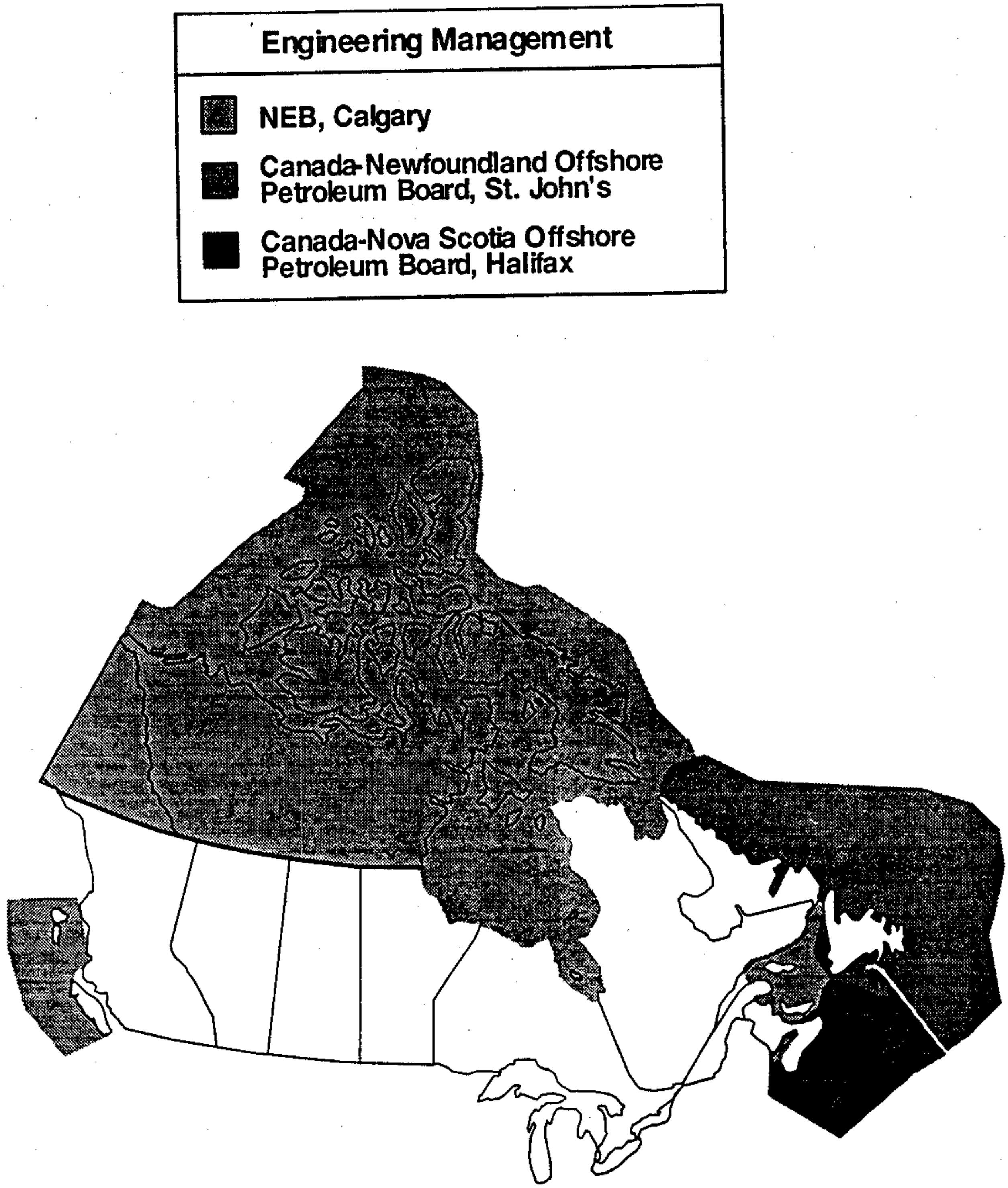
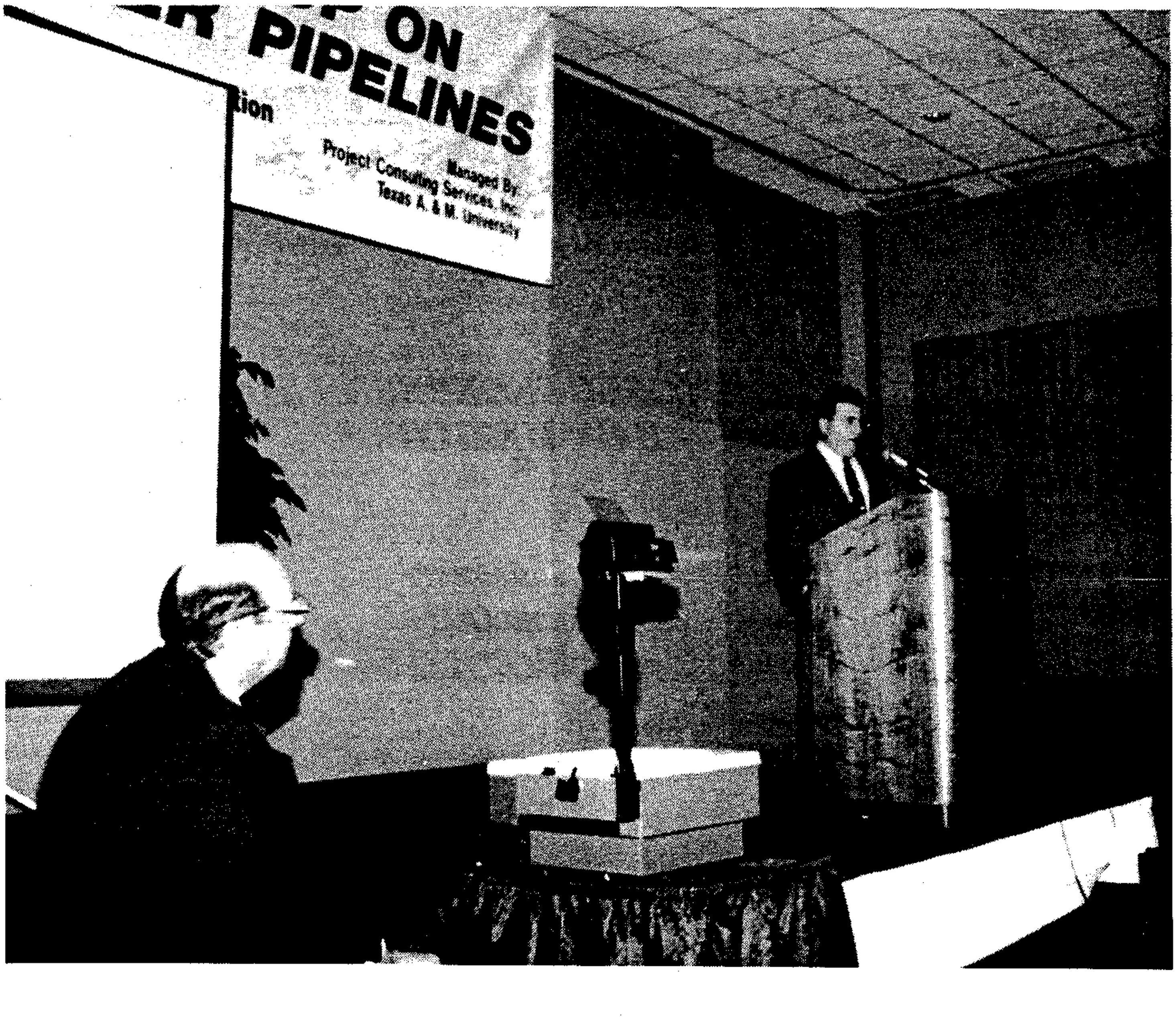


Figure 3 - Frontier Oil and Gas Activities and Responsibilities

KEYNOTE PRESENTATION I

"CONTRACTING CONCERNS IN THE GULF OF MEXICO"

Dan Houser
McDermott Inc.
Morgan City, La.


PIPELINES
Managed By:
Project Consulting Services, Inc.
Texas A. & M. University

Introduction

One of the most important components of completing a successful project, is to define the situation. Typically this might require information on at least the following components: location, water depth, repair support techniques, initial response, and remedial response options.

The location might typically vary between open water situations, inshore waters, and marsh locations. Water depth could be anything from shallow to deep to very deep. Repair support services could involve surface support, or diver support, or the use of remotely operated vehicles (ROV's). The initial response to a spill might initially involve containment, and the remedial response would normally be pipeline repair.

As an example, Figure 1 shows the decreasing options available for support vessels, as a function of increasing depth.

Safety and Environmental Concerns

Additional key issues involved nowadays involve planning for safe operation and in minimizing impact on the environment. In many cases these can interact with each other, as shown in Figure 2. Typical concerns that need to be considered in project planning are as follows:

- Personnel exposure and toxicity
- Vessel damage, loss prevention and clean-up
- Pollution and environmental damage
- The possibility of fire
- Coastal/inshore mitigation
- Seasonal and weather constraints

Human Resources

Management of human resources is especially important in today's economic climate. As the number of technical options decrease, the need to improve training and skills increases, as shown in Figure 3. Issues and concerns related to human resource management include the following:

- Project management
- Planning and engineering
- Availability of necessary skills (including real time inventory constraints)
- Education and training
- Industry awareness

Technical Issues

An effective approach to a major repair project requires consideration of these concerns:

- Open water spill containment and recovery
- Response time
- Access to the pipe (is isolation possible? is it buried? is it piggable?)
- Condition of the pipe
- Pipe cutting methods available
- Relative merits of repair at depth versus retrieval to the surface
- Hardware options and availability
- ROV tooling and standardization

Equipment

Special concerns as far as equipment is concerned, include the following:

- Availability
- Special tooling
- Diver and ROV capabilities
- Equipment preparedness & pre-placement
- Customer awareness of contractor capability
- Contractor awareness of customer requirements
- Survey equipment and data

As Figure 4 shows, the options available for access and repair, vary greatly with depth. Surface air diving is viable for pipelines less than about 60 m. (190 ft.) deep; surface gas diving down to 100 m. (300 ft.), saturation diving from there down to about 300 m. (1000 ft.), and a 1 atmosphere suit down to 700 m. (2250 ft.). Below this, ROV use is necessary - these now operate to depths of 2000 m. (6000 ft.) and more.

Regulatory Issues

As any successful operator will know, it is always necessary to be fully conversant with the regulatory requirements, typical components of which might be:

- Reporting responsibilities
- Certification of personnel
- Certification of equipment
- Regulatory agency requirements, namely Coast Guard, M.M.S., and D.O.T.
- OPA 90

Commercial Considerations

As with any business venture, the normal issues related to commerce must also be considered, such as:

- Liability and indemnity
- Insurance notification and response
- Partnering and alliances
- Customer confidence and openness
- Remuneration
- Financial depth and health

The Gulf of Mexico is no exception in this respect, but it is encouraging to note that, despite uncertain times, the offshore and underwater pipeline industry continues to prosper, and we anticipate this trend to continue.

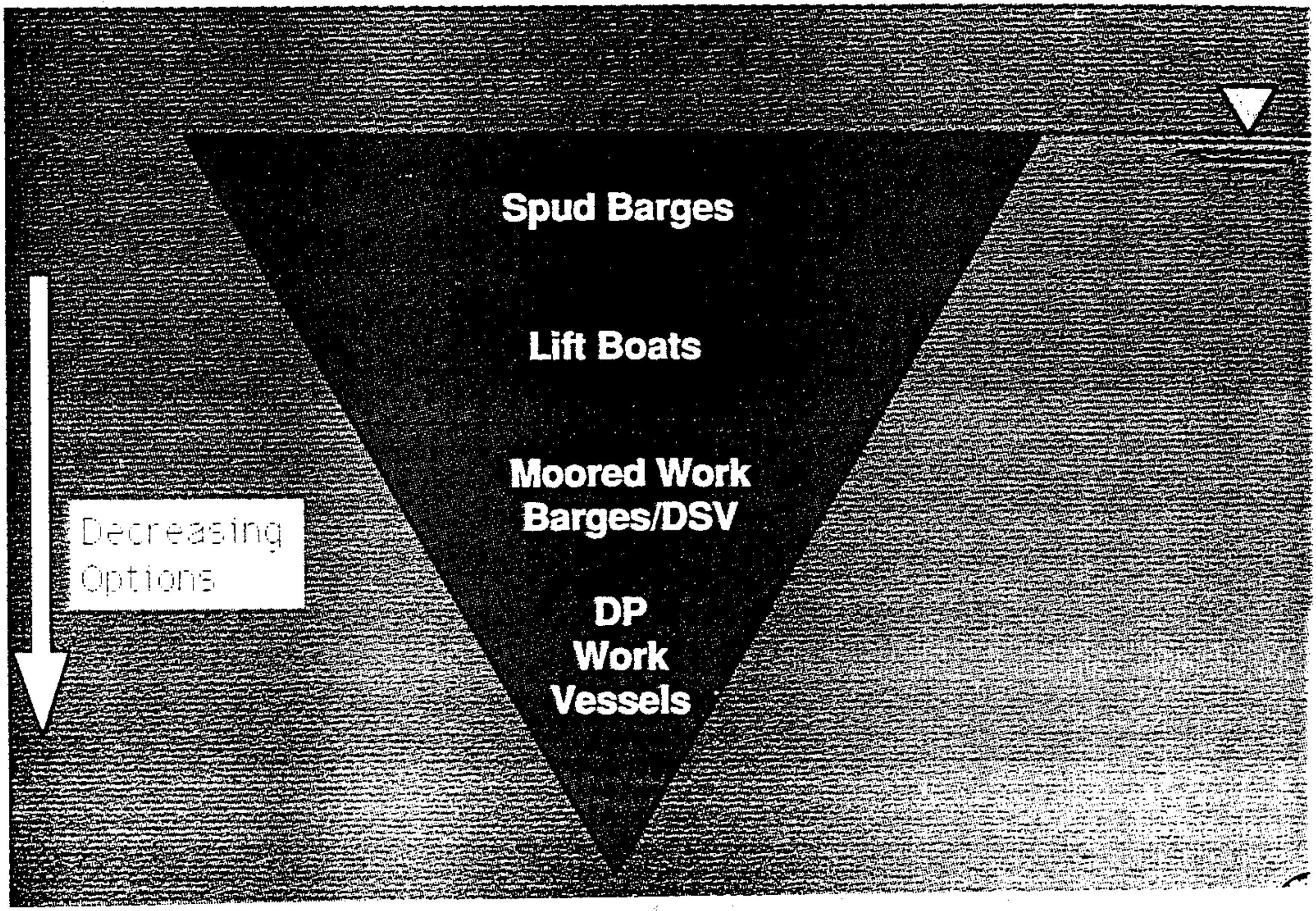


Figure 1 - Support Vessel Options with Depth

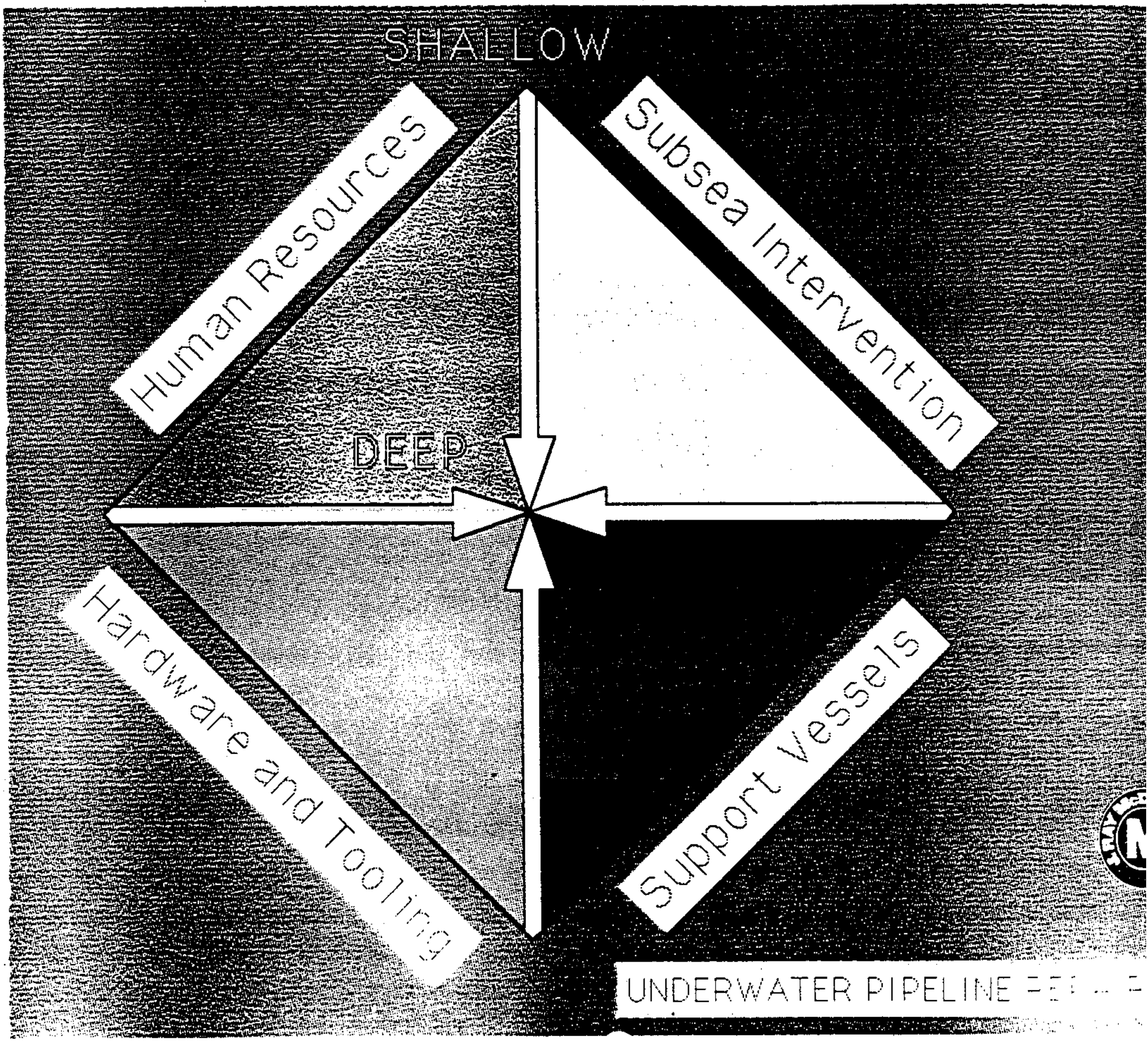


Figure 2 - Interaction of Issues for Underwater Pipeline Repair

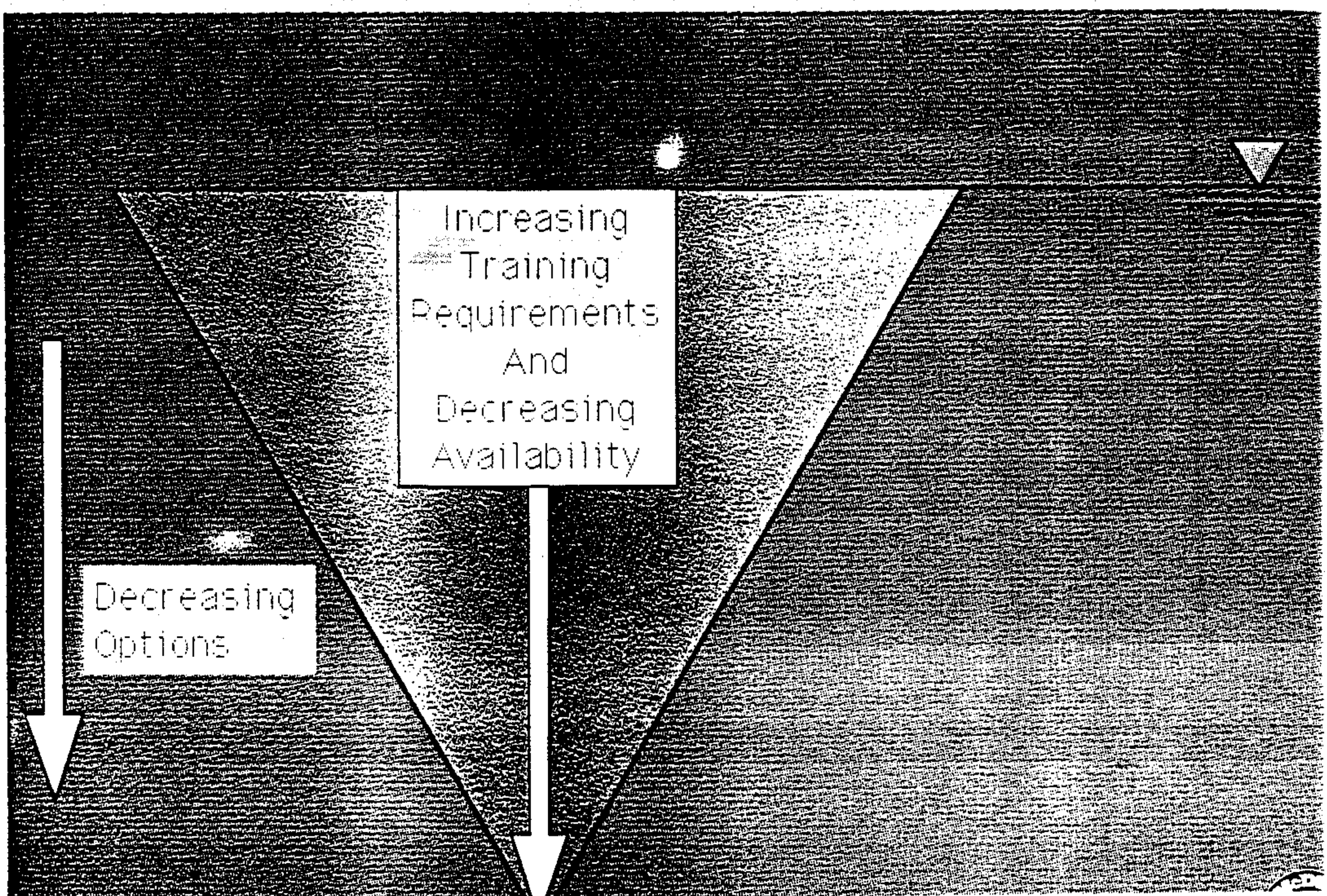


Figure 3 - Decreasing Options Related to Human Resources

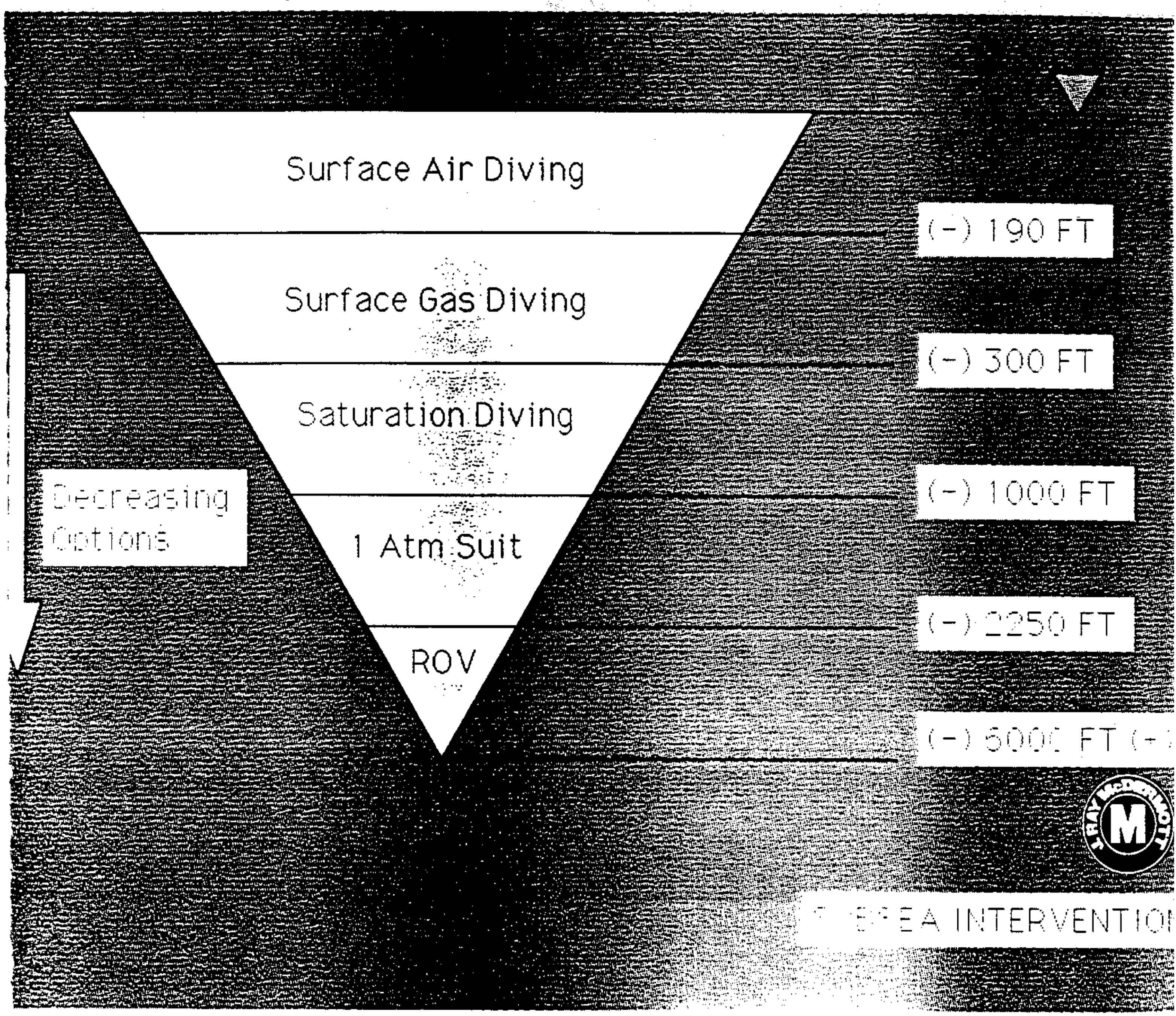
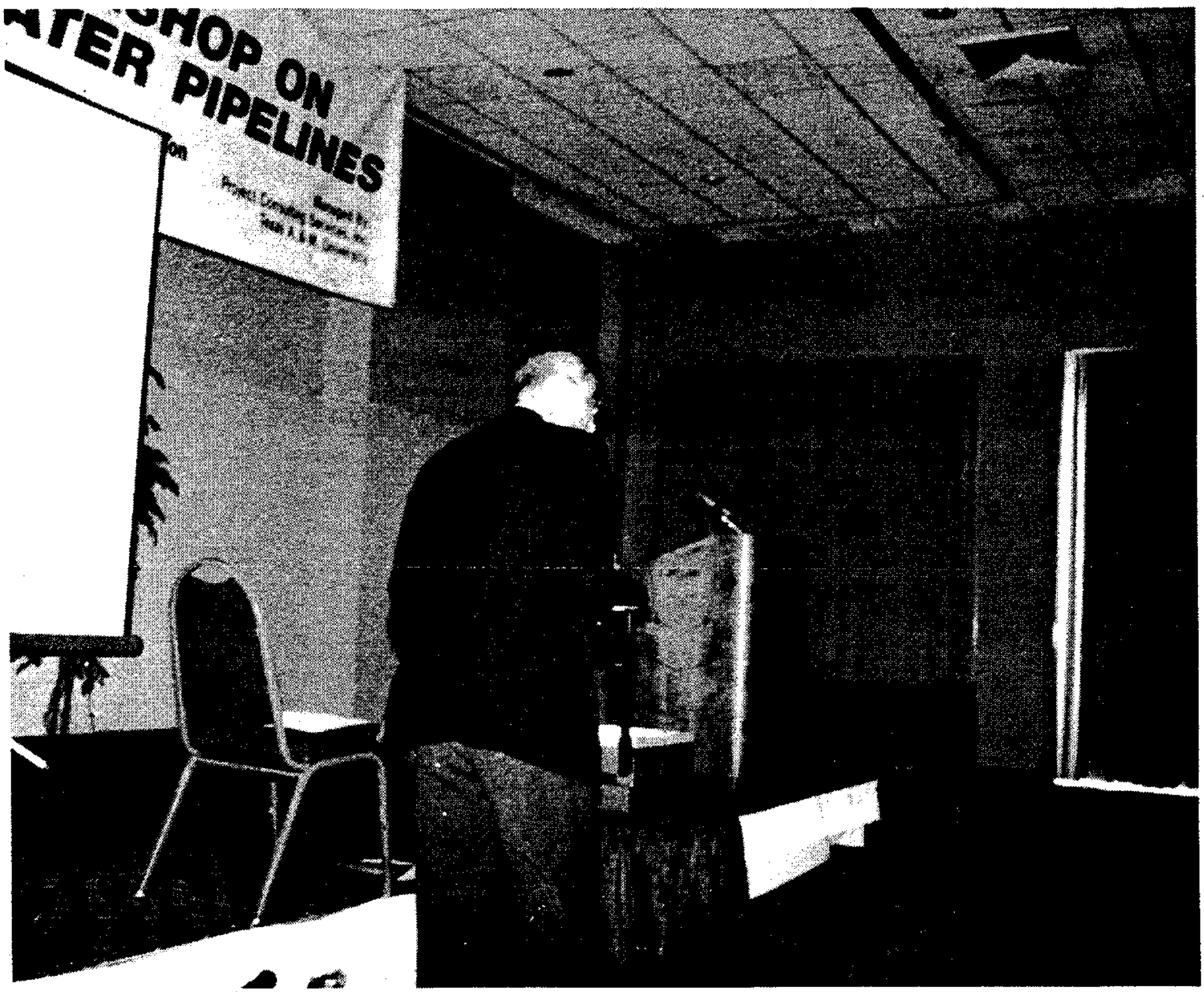


Figure 4 - Subsea Intervention Options as a Function of Depth

KEYNOTE PRESENTATION II

"HAZARDS FOR PIPELINES IN EUROPEAN WATERS"

Roberto Bruschi
Snamprogetti S.P.A.
Fano, Italy



HOP ON
TER PIPELINES

Abstract

Hazardous scenarios for offshore pipelines are mainly associated with deep water pipe on uneven seabeds, or with shallow water pipelines affected by severe environments and unstable seabeds. Further, earthquake hazards may imply additional concerns as well as severe hydrodynamic fields impacting on the pipeline free spanning over irregular seabeds. In the European Continental Shelf the congestion of human activities renders the associated hazards more severe than those from the environment in such a way as to dictate restrictive design criteria.

Under these circumstances, advanced engineering coupled with accurate installation and adequate surveying is required to tackle the operating life with adequate reliability against loss of structural integrity, and with reasonable investment costs.

Introduction

The term "Environmental Hazard" is normally adopted both for the consequences of pipeline failure in connection with the quantity of product dispersed in the environment, and for exceptional environmental loads which might cause the established usage factors to be exceeded, thus resulting in possible malfunction or even pipeline failure. This paper refers to the second definition, closer to the terminology used in the subject discipline (the term "environmental impact", for instance, can be applied to the first definition) and attempts to relate the occurrence of exceptional events caused by adverse environmental conditions with the remedial measures adopted to avoid triggering of potential failure modes of the pipeline.

Subsea pipeline failure statistics, referring to about 20 years performance of the main transmission systems operating in the world, show few incidents induced by excessive environmental loads, such as those induced by excessive hydrodynamic loads associated with exceptional storms or hurricanes as well as seismic excitation (Eiber and Jones, 1992, and Adams, 1993). Among the few cases known, are the incidents in the area offshore of the Mississippi Delta, caused by the contemporaneous action of exceptional hydrodynamic loads and instability of loose sediments, mobilized by the hurricanes affecting the site (Bea and Aurora, 1983).

Another example refers to the North Sea where pipe flotation occurred right after the pipeline had been launched (Strating, 1981). This event was caused by the loss of the concrete coating due to a first damaging on the laying ramp and, afterwards, to the impact on the sea bed of suspended sections of the pipeline on the scoured bedline caused by vortex shedding induced oscillations.

The reasons for scanty failure statistics (true in general for offshore pipelines and particularly for incidents ascribable to environmental hazards) are certainly due to the restrictive design criteria adopted to tackle environmental loads. Indeed, for a long time, in-place stability and free span assessment against on-bottom hydrodynamic fields impacting on the pipeline, have been one of the main aims of research on submarine pipelines. It appears that there has been some agreement on the conservativeness of related design criteria (Anselmi and Bruschi, 1993).

It is difficult to separate clearly what can be defined as sound design, from conservative design, particularly in a field with such limited experience in harsh offshore conditions. It is however true that the use of very restrictive criteria may result in a wrong evaluation of the project economics or even its feasibility, particularly for the highly challenging projects presently in the planning stage. On the other hand, restrictive design criteria focused on the pipeline may not be sufficient for an overall reliability of the transportation system.

In many circumstances, design criteria should be supported by a thorough characterization of the meteo-oceano-geo-morpho-seismo- environment, much more accurately than is normally proposed in offshore pipeline technology. As an example, current studies regarding the feasibility of the Oman-India pipeline, or of other alternatives in the same region, must consider a comprehensive environmental characterization (Estaugh, 1994).

In the European Continental Shelf, detailed studies on environmental hazards have been carried out with special regard to two specific problems:

- The combination of particularly adverse weather conditions with relatively shallow waters and unstable sediments, a typical situation of the Southern North Sea and in particular across the coastal regions of Central Europe. Trunklines between the giant gas reservoirs of the North Sea and Europe are particularly affected by these problem areas (Bruschi and Iovenitti, 1993).
- The severe seismic environment, particularly in the Central and Eastern Mediterranean basins, impacting on difficult geo-morphological conditions encountered on the continental shelf and slope. Mediterranean pipeline crossings between North Africa and Sicily and between Sicily and the Italian mainland are particularly affected by these adverse conditions (Albano et al., 1992).

Furthermore, for the pipeline crossings of the Southern North Sea, a topical but indirect issue linked to the environmental hazard is the interference of the pipeline with third party activities. For this aspect, failure statistics are quite eloquent: external impact from third party activities appears to be the most likely cause of pipeline failure (Bruschi and Vitali, 1994). Most of the pipeline failures due to external impact, occurred during construction activities in the area near offshore platforms, where intense vessel traffic and load handling could cause accidental events interfering with the subsea pipeline. External impact in the open sea is less likely to occur, and is mainly correlated to fishing activity, ship traffic and offshore operations. Further investigation of failure statistics shows that the probability that an impact would cause a leak, decreases with pipe diameter, due to the effect of the increase in wall thickness (Bruschi et al., 1990).

The relationship between third party activities and environmental hazards is two fold:

- Design criteria imply that the interference between the pipeline and an external activity shall be considered as an environmental load for high interference frequencies (e.g. larger than 10^{-4} per year), (Norwegian Petroleum Directorate, 1990). Impact loads from fishing gear are often classified as environmental loads (at least one hit per pipeline joint during the operating life span in many sectors of the North Sea), requiring high costs for protection measures.
- In many circumstances where environmental issues are topical, protection measures against and for third party activities often imply considerable burial depth and/or protective cover effective for the operating life span. This aspect deeply affects construction criteria and technology (e.g. lowering the pipeline across a shipping lane) and the inspection and maintenance programs.

It is not the scope of this paper to deal with the implications of environmental hazards on protection criteria for pipelines crossing areas congested with third party activities. Discussions on this topic can be found in the subject literature, (e.g. Verley, 1994). Some of the new concerns are being addressed in further applied research efforts. Assisted laying in narrow corridors across difficult seabeds (Bruschi et al., 1993 a) and ultra-deep water laying and intervention technology (Rosa and Brandi, 1994; Magnelli and Radicioni, 1994) are present issues. Tackling the new hazardous scenarios in a cost effective way, is another issue. Moreover, offshore industry is calling for rationalization of design and operating criteria, in particular for those project criteria inherited from on-land pipeline technology, (Sotberg and Bruschi, 1992).

Research and regulatory bodies are targeting new design criteria for offshore pipelines which may be different depending on the products, operating strategies, different environments, different materials, etc. This new effort, coupled with further advances in engineering and environmental sciences, is the key to future projects in increasingly harsh environments which involve considerable investment costs.

Severe Sea-States and Sediment Movements in the North Sea

Environmental hazards are of primary concern in the design of submarine pipelines which are exposed to a combination of severe meteo-marine conditions, relatively shallow water and potential sediment instability. A threat to pipeline integrity might be an unexpected exposure to hydrodynamic loads especially in the case of a suspended pipeline, subsequent to the loss of the bearing sediment.

A pipeline lowered into the seabed by post-trenching works, with concrete coating designed to guarantee on-bottom stability in the early stage of construction before natural backfilling, could subsequently be subject to exposure, e.g. as a consequence of liquefaction of the backfill material or activity of bedforms. This could give rise to excessive lateral displacements possibly inducing permanent strains accumulated in a few pipe sections close to fixity points (such as buried lengths and anchoring points). Further consequences of excessive lateral displacements might lead to serviceability problems such as interference with neighboring structures and seabed obstacles, or excessive ovalization at the strained section.

Free spanning could be the evolution of unexpected exposure, or a possible scenario foreseen in the design stage but not properly quantified in advance. Free spans exposed to cross currents and wave induced velocities might undergo flow induced oscillations causing fatigue damage at girth welds (Bruschi et al., 1986), or, at worst, cyclic overstress at the pipe sections where strains are accumulated (e.g. at the shoulders of free spans). Furthermore, concrete coating might be lost as a consequence of impact against the seabed (Strating, 1981), causing pipe flotation. The consequences of sustained cyclic loading might be rupture, e.g. either bursting under internal pressure after the ultimate material capacity is reached due to excessive deformation; or leaks at a defect as a result of fatigue crack propagation e.g. at the girth welds.

Current design practice against environmental hazards due to a combination of severe meteo-marine conditions, relatively shallow waters and potential sediment instability, is mainly tackled with proper selection of concrete coating thickness linked to burial depth criteria. In general, a deterministic approach is applied, not directly considering risk levels or cost-benefit estimates. However, environmental uncertainties make rationally based burial criteria unable to eliminate the risk of occurrence of unexpected exposure and suspension, e.g. where active bedforms or liquefaction of backfill could make the pipeline upheave for lengths which might be critical even in case of exposure and suspension for a limited time interval.

Unexpected Free Spanning

In shallow waters and severe meteo-marine conditions, exposure and suspension lengths might be critical for fatigue damage and excessive response under cyclic hydrodynamic loads. The vibratory response of the pipe either suspended over or sagged down into the scour trench is strongly affected by the position of the pipe with respect to the bottom line of the trench (Sumer et al., 1989). This influences the assessment criteria of scour induced free spans in the same way as the trenching depth and profile influence the force coefficients for horizontal and vertical stability of a pipeline resting on the bottom of the trench (Jacobsen et al., 1989). Focusing on the hazard associated with free spans induced by sediment instability, pipeline engineers had to face different problems according to the potential suspension scenarios:

- Pipeline untrenched, with scouring and relevant development of free spanning lengths, as in the case of STATPIPE. Eide et al. (1988) showed that local erosion in the proximity of the pipeline caused the development of scour induced free spans for a large extent of the route across the sandy seabeds and shallow waters (70 to 80 m.) of the Ekofisk plateau, see Figure 1. A comprehensive study documented the structural integrity in the long run of the final pipe-seabed configuration, and established the criteria for monitoring unexpected developments through inspection. Ten years of satisfactory performance testify to the adequacy of the developed criteria and tools.

- Pipeline possibly to be trenched after 1 year from construction in case self lowering is not sufficient to shelter and anchor the pipeline. In this case the pipeline has to overcome a winter season under exposure, and withstand potential periodic suspension without suffering from excessive damage. Anselmi and Bruschi (1993) showed that, in shallow waters, the development of scour induced free spans may be quite critical. In the short term, e.g. the time interval for a single storm, free spans can develop up to their maximum lengths and, consequently, the pipeline can be subjected to significant hydrodynamic loads which may jeopardize the structural integrity of the pipeline in the short run, see Figure 2.

- Pipeline previously trenched (maybe improperly) and partially or totally covered by natural backfill. Upheaval may occur due to looseness of cover and susceptibility to liquefaction. The pipeline may become exposed due to large migration of the superficial sandy layers. The pipeline has to survive the time period between inspections without suffering from excessive damage, so that remedial measures can still be successfully implemented. Krogh and Nielsen (1993) showed that the DONG pipelines, previously trenched and naturally backfilled, suffered from exposure and consequent development of free spanning due to extensive erosion processes, see Figure 3. Detailed studies and specific surveys were carried out to assess the structural integrity of the pipeline. Considerable remedial action was needed in the proximity of the valve assembly protection cover, where the scouring was enhanced by the presence of the steel plates protecting the valve, developing to unacceptable levels.

- Pipelines laid in areas affected by active large scale bedforms, and suitably lowered by pre-sweeping and/or post-trenching works to avoid either free spanning or exposure in the lowest points of the seabed profile. Schaap (1989) showed that sand wave migrations influence the state of stress of a pipeline, but the evolution is not expected to create unacceptable conditions as settlement of the pipeline should contribute to overall straightening. An application of design criteria for crossing sand wave areas was carried out in the ZEEPIPE Development Project. The Zeepipe crosses about 200 km of sea bottom with sand waves through the southern part of the Dutch sector and through the Belgian sector of the North Sea. The height of the sand waves varies from a few meters to a maximum of 8-10 meters. The distance between the crests is typically in the range of 150 to 500 m. To determine modes and rates of sand wave mobility, general data from relevant literature and from surveys performed at different times in the same area, were analyzed. The pipeline response to the migration of the sand wave pattern was analyzed assuming that the translation of the entire sand wave occurred without a change in shape, as shown in Figure 4. The results confirmed the prediction that the pipeline tends to settle and straighten in the long run. However, the critical temporary conditions in areas of exposure and free spanning, caused the pipeline profile to be ruled principally by the environmental hazards and not by the usual stress criteria. This prevented full utilization of the deformation capacity of the pipeline (Bruschi and Iovenitti, 1993).

There are, obviously, other project experiences in the southern North Sea, of rather standard pipeline concepts where in-place stability is still a challenging aspect, as well as for the above mentioned case histories (Lemercier and de Vries, 1992).

Integrated Approach to In-Place Stability

During the detailed engineering of the Sleipner to Zeebrugge pipeline, a number of studies to formulate the requirements for concrete weight coating and trenching were performed (Bruschi et al., 1993 b). The studies were particularly related to the conditions in the Dutch Continental Shelf, characterized by shallow water, relatively severe sea-states and locally active bedforms. Some of the most interesting studies were on the self-lowering of the pipeline as a topical issue for formulating design criteria tailored to site specific environmental hazards. The problem was studied in depth using state-of-the-art tools available at the time. The results were used in determining both the construction schedule and a strategy for post-trenching. The studies resulted in an integrated approach based on a new classification of trenching priorities with respect to specific in-place stability criteria (see Figure 5).

- Pipe with concrete thickness required to ensure stability in the operating conditions. The maximum length of scour-induced free spans is expected to be less than the allowable length in both empty and operating condition, i.e. the limit length beyond which hydrodynamic loads may cause unacceptable fatigue damage. No action required.

- Pipe with concrete thickness required to ensure stability in the operating condition, for which span lengths in excess of the allowable may develop in the long term due to seabed mobility and/or extensive scour. No immediate action required, but careful monitoring is recommended.

- Pipe with concrete thickness required to ensure short term stability, for which the potential for self-lowering has been identified. Problems related to scour induced free spans may be evident as above, otherwise see the next section. It is recommended to postpone any action to the season following installation, possibly requiring that the pipeline be flooded during the winter season to enhance the process of self-lowering. The degree of self-lowering attained should be determined by a survey two or three seasons after construction.

- Should self-lowering, in addition to the immediate settlement, be found to be in excess of a significant fraction of the pipe diameter, no action is required. Otherwise post-trenching of the pipeline to a total depth of 0.5 to 0.7 diameters is recommended. The maximum length of scour-induced free spans expected is definitely in excess of the allowable, even in the short term. Problems related to on-bottom stability may or may not exist. Trenching should be performed as soon as possible after laying, to avoid the possibility that a storm may cause unacceptable damage to the pipe.

The as-laid and self-burial surveys confirmed the expectations regarding the immediate and after-one-winter self lowering in areas with loose silty sands and medium to dense sands. It is of particular interest that the most optimistic forecast based on the theoretical modelling (namely a lowering of more than 0.5 D for a stretch totalling more than 40 km) was confirmed. The post-trenching strategy, based on a detailed evaluation of the hazards resulting from exposure and potential free spans during the first winter season and on the potential for self-lowering, resulted in reducing trenching by 75 km.

Shore Approaches and Morphodynamic Hazards

Morphological hazards are a peculiarity of shore approaches characterized by significant seabed variations with time. Seabed erosion and bedform activity are often the main causes for morphodynamics which occur in the form of sandbank and sandbar migration in connection with seasonal current and sea state variations, or in the formation of new tidal channels where the coastal currents are concentrated particularly in mudflat areas. In addition, sediments found in coastal areas may be subject to liquefaction under the cyclic action of surface waves. This reduces the containment action of the soil relative to the buoyancy of the buried pipeline, which may float in the water-sediment mixture.

Soil liquefaction may cause the exposure of long pipeline sections originally buried into the soil and not designed to withstand hydrodynamic action. A significant example which did not result in pipeline failure due to the limited extent of exposure, occurred in the near shore area of the NORPIPE pipeline (Borcherding and Knutsen, 1987). Liquefaction caused a general lifting of the pipeline from the construction depths (-3 m from the bedline) up to -1.5 m from the bedline for long sections nearshore the Isle of Juist. In addition, sandbar migration and the profile variation of a tidal channel in the mudflats, caused exposure of the pipeline, as shown in Figure 6. Attempts to solve the problem were made by dumping crushed rocks to protect the pipeline against hydrodynamic loads, but this protection disappeared in a short time.

The following are some successful construction solutions which provide details about this specific aspect (see also Raven, 1992) :-

- The DONG pipeline shore approach, in the western coast of Denmark, has a sandy nature with significant sandbar mobility. For the construction, special consideration was given to the time scale of the sedimentation process for the long trenching corridor, as shown in Figure 7. Utmost care was also taken in defining the trench depth. Historical data analysis and modelling of coastal morphodynamics was used to define a project value, with a one-year probability of non-exceedance, of the lowest point which the bedline was expected to reach (Krogh and Nielsen, 1993).

- A more recent example is the ZEEPIPE pipeline shore approach, a section of about 10 km. close to Zeebrugge port (Eide et al., 1993). Besides the problems caused by loose sediments and morphodynamics, there were additional hazards due to intense ship traffic in the navigation channels. The proposed solutions, which have so far proved to be successful, were aimed at defining measures to ensure the maximum stability of the pipeline at the selected burial depth, in order to meet ship traffic protection criteria.

- One of the latest examples is the EUROPIPE pipeline nearshore approach, still in construction, and the entrance in mudflats through a tidal channel between sand islands. These were both areas characterized by intense morphodynamics, as outlined in Figure 8. In this case the concept of morphological design basis, i.e. the lowest profile expected in the long run for bedline variation referred to the mean sea water level, has been further refined through the analysis of historical data, the simulation of different hydrodynamic and sediment transport regimes and the simulation of morpho-geo-dynamics (Bijker et al., 1994).

Seismic Hazards in the Mediterranean

While there has been a general consensus on seismic design procedures for underground pipelines for some years (e.g. ASCE 1984), the need to establish similar design procedures has not yet been recognized for offshore pipelines. The main reason for this is that, in most circumstances, any damage to the pipeline resting on the seabed or on the bottom of a naturally backfilled trench, induced by an even severe seismic crisis, is definitely a remote hazard. The almost rectilinear configuration of the pipeline can withstand the travelling deformation wave in the elastic range without triggering any failure mechanism, due to the pipeline flexibility with respect to the deformation scale.

Nevertheless, in some circumstances (such as a pipeline mostly free spanning over the bedline and more or less regularly supported by protruding rocks, smooth undulations or artificial supports such as mechanical trestles or gravel berms) a detailed analysis may be required to document that seismic excitation does not threaten the bearing capacity of the natural or artificial supports and the structural integrity of the pipeline.

There are also routes and configurations which may need specific attention, notably: pipelines crossing faults, potentially active, protruding from the seabed and possibly creating a free span; laying corridors characterized by soil layers susceptible to instability due to slope shear failure or liquefaction during seismic excitation, also producing abrupt scarps or turbidity currents.

In both circumstances, or in other conditions less critical but still requiring an assessment of structural integrity such as "T" connections, bends, connection to fixed structures etc., a detailed seismic analysis is required.

During the last years, seismic hazard assessments have been performed regarding the pipelines crossing the European Continental Shelf. This has been done for the systems crossing: the flat seabeds of the southern North Sea like the Zeepipe pipeline (Diamantidis et al., 1992); the undulating seabeds of the Norwegian Trench and the rocky seabeds at the entrance of the Norwegian fjords (Breivik, 1994); and the undulating seabeds and shore approaches of the Mediterranean pipelines in the highly seismic region of the Strait of Messina.

Seismic Hazards in the Strait of Messina

Southern Italy is dominated by the presence of an inter-continental plate boundary, the Calabrian Arc, which extends from Central Italy through Northern Sicily into North Africa and represents a collision zone where the African Plate is in contact with the European Plate. In this tectonically disturbed area, young and often active volcanoes exist, such as Stromboli, Vulcano and Lipari in the Eolian Islands, and Etna in Sicily. Seismic activity is concentrated along this arc. Based on the geological setting of the area and the historical data, the area can be divided into various seismic-tectonic provinces, which separate different levels of seismicity.

The epicenters of the earthquakes with the highest magnitude are predominantly distributed in the Crati and Messina valleys, close to the Thyrrenian Sea. The shocks generally originate in the crust with focal depths of about 20 to 30 km., as shown in Figure 9. Further, turbidity current motion in the Messina Strait and also tsunamis have been observed in the case of strong earthquakes, and have been related to seismic events of high intensity. The strongest historical and instrumentally recorded event in the province was the December 28, 1908 Messina event which occurred with Intensity XI and an estimated Magnitude of 7.1.

The analysis of ground motion intensity for an early assessment of the seismic hazard of the pipeline link, included the calculation of the probability of exceedence of peak ground acceleration at the site, the estimation of the recurrence rate of seismic events within the region, and the assessment of the upper bound magnitude for a given appropriate attenuation relationship. In addition, the seismic time history characteristics were evaluated, including derivation of typical response spectra and analysis of actual measured response spectra relevant to the site. The probability of exceedence of fault displacements interfering with the transmission system was also calculated, based on: the relation of fault displacement to fault length and magnitude, the association of recurrence rates with the different faults, and the probability of exceeding a given fault displacement.

For the estimation of recurrence rates and upper-bound magnitude, the recurrence rate was assumed to be spatially uniform within each seismotectonic province and to decrease exponentially with the magnitude of the earthquakes. The upper-bound Magnitude for the province was assumed to be 7.6, i.e. one-half unit higher than historically observed, which is consistent with normal practice. For the estimate of the probability of exceedence of peak ground acceleration, the method proposed by Cornell (1968) was used. To provide information on how seismic parameters attenuate with distance from the origin of an earthquake, different attenuation relations were used based on world-wide data, as there was a substantial lack of adequate site-specific data. Figure 10 shows peak ground accelerations versus return period curves. A sensitivity study showed that only the homogeneity of the spatial distribution of earthquakes with magnitude larger than 5.5 and at a distance less than 50 km. to the site, was influential.

The characteristics of the earthquake induced motions were based on the shape of the response spectra as proposed by various regulatory commissions and on an evaluation performed according to a frequency dependent attenuation law. The proposed spectrum was close to that recommended by API (1986) for deep alluvium at very low frequencies but higher at intermediate frequencies, as shown in Figure 11. To obtain a response spectrum that accounts for the dependence of the frequency content on the distance of the earthquake to the site, a probabilistic analysis was performed for different periods of oscillation, utilising the approach outlined by Cornell (1968) together with a frequency dependent attenuation law based on Trifunac and Anderson (1978) and Trifunac (1980).

Figure 12 shows an acceleration time history, based on a record of an earthquake which occurred on 15th April 1978 with a magnitude of 5.5 and epicentral intensity of VIII at 38.25° North and 50.1° East with focal depth of about 24 kilometers. This record was used as a starting point to generate an artificial time history consistent with the design spectrum, using the approach outlined by Rizzo et al. (1975). The statistical analysis of fault motion was based on historical data compiled for normal faults, to determine regressions of the earthquake magnitude M to the fault length L and maximum fault displacement D (Slemmons, 1977). For this application however, only a small fraction of earthquakes would produce fault displacements and therefore, peak displacements were strongly dependent on the homogeneity assumption.

Stability of the Landfall in the Strait of Messina

Seismic slope stability in high seismicity areas is particularly relevant offshore, where even gentle slopes of marine sediments may deform or fail during strong motion earthquakes. In the shore-approach areas relatively steep slope angles are not uncommon. Temporary exceedance of the soil shear strength and progressive strength degradation associated with pore pressure build-up, may lead to permanent deformations in the soil. Messina Strait soil is mostly characterized by dense sand and gravelly sand, with relative densities often in excess of 60 per cent. These soil types extend to depths of several hundred meters below the bedline and completely dominate the landfall areas.

Several 1-D seismic response analyses were carried out using the program SHAKE, (Schnabel et al., 1972), in order to compute the earthquake-induced stress and strain distributions with depth, throughout the Messina Strait area. The earthquake motion was assigned to a rock outcrop at a depth of 380 or 500 meters, depending on the location of the borehole being analyzed. The stress ratio profiles for the six locations considered in the analysis are summarized in Figure 13.

Due to the dense state and to the medium to coarse size of the granular soil and also based on observations of experienced instabilities in the Strait area, complete liquefaction and earthquake-induced slope collapse was deemed unlikely. Laboratory tests confirmed that this material behaved in a dilatant manner during shear, and had high resistance to liquefaction. However pore pressure build-up leading to soil strength degradation and consequent deformations, might be expected under cyclic loading (De Alba et al., 1976). Depending on the seismic event considered, the operability of the system may also be a concern in the case of relatively large deformations.

The slope displacements were computed by a sliding block procedure, with the displacements in the soil mass computed by double integrating the acceleration time history portion exceeding the yield acceleration, as schematically depicted in Figure 14. The yield acceleration is defined as the acceleration value at the ground surface for which failure occurs along a potential sliding plane (Newmark, 1965).

The settlements due to pore pressure dissipation were computed based on the correlation presented by Tokimatsu and Seed (1987). The vertical settlements associated with strong motion earthquakes are mainly due to excess pore pressure dissipation. This depends on the shear stress ratio experienced by the soil during the earthquake and on the SPT blow count. The latter parameter was conservatively estimated based on the available CPT soundings, applying correlations given by Robertson et al. (1983) and Kulhawy and Mayne (1990). This analysis predicted vertical strain of 1.2% from the surface to 15 meters depth, resulting in a total settlement of about 20 centimeters (Pelli et al. 1994).

Further evaluations included the turbidity current hazard analysis and the analysis of seismic wave propagation from bedrock using non linear models. Therefore in the area crossed by the offshore pipeline shown in Figure 15, the seismic hazard has now been thoroughly documented.

Subsequent upgrading works have included two new lines, the installation of which have recently been completed (Albano et al., 1992). The new shore approach to the Italian mainland is shifted to the north due to offshore link optimization and also in a location where seismic hazard is lower. Additional studies concerned the assessment of the structural integrity of the load bearing structures involving the pipeline under and after a seismic excitation, as well as studies for assessing the worthiness of the pipeline to withstand local settlements.

Thick offshore pipelines, designed to withstand deep water installation loads, high design pressures and possible seabed unevenness, are quite ductile and can absorb large local settlements. They therefore generally behave better than onshore pipelines, which are usually sized for lower design pressures and have thinner wall thicknesses (diameter to thickness ratio of 25 to 45 for offshore pipelines as opposed to 60 to 120 on land).

The final performance of the Strait of Messina pipelines (three 20" lines laid in the late '70's) in about 15 years of operation, has proved to be satisfactory. During this period, seismic activity was minor and only a few local events have been recorded, although there has been some surveyed evidence of soil settlements attributable to a seismic event, close to the Sicilian shore approach in an area characterized by mild slopes (about 8^{o}) in medium to coarse sand with low relative density.

Conclusions

Future submarine pipeline projects involve increasingly difficult environmental settings. The entrance into the Norwegian fjords, the Gibraltar Strait crossing, a submarine link between Oman and India are relevant examples. It is therefore timely to establish a new approach to assessing environmental hazards. Initial examples of this new approach have been developed in the design of the pipelines between the North Sea and the European continent, and across the shallow waters and unstable coastal zones of Belgium, Holland, Germany & Denmark.

The integration between ocean and coastal engineering on one hand and between design criteria, construction strategies and inspection programs on the other, have resulted in significant progress in both cost and reliability.

The same can be said for seismic analysis in the Mediterranean and Messina Strait crossings, where in-depth studies of the earthquake engineering issues have made fundamental contributions to the route definition, and to the final engineering solutions.

Targeting design criteria and providing rationally based safety levels with respect to project/site specific hazards, require full and accurate analyses of failure modes that may be experienced or which can be anticipated for all operating conditions.

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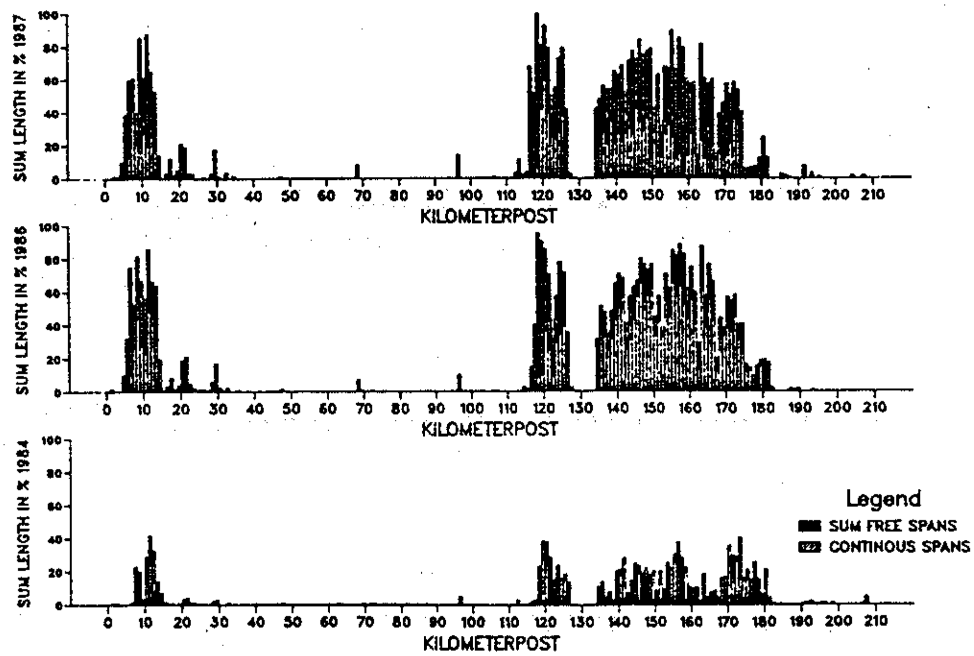


Fig. 1 - STATPIPE System 34 : freespan lengths per kilometer

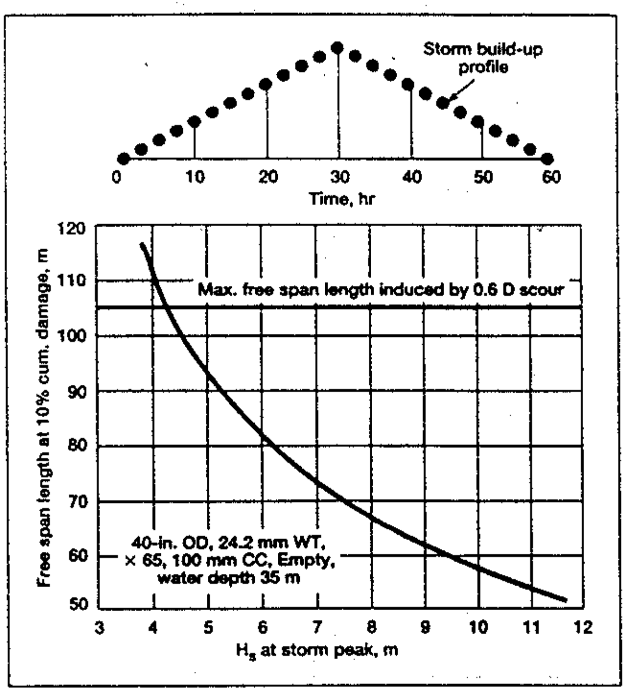


Fig. 2a - Zeepipe cumulative storm fatigue damage through a scour induced free span due to wave-induced oscillations

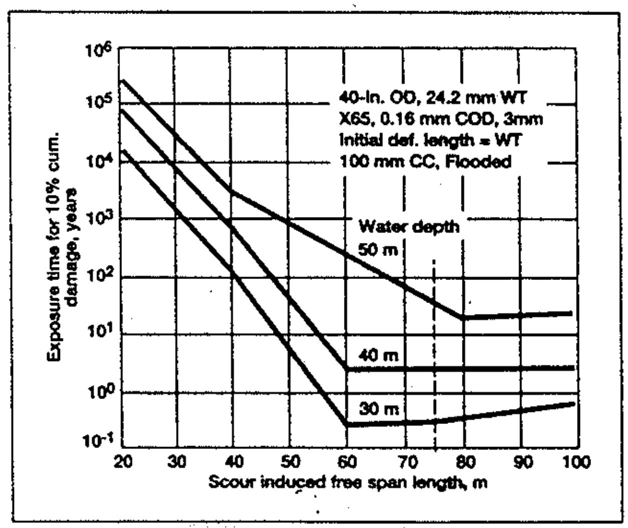


Fig. 2b - Zeepipe: exposure time for 10% cumulative damage

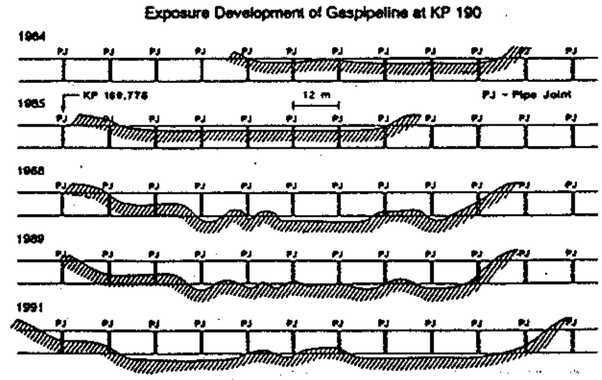


Fig. 3 - DONG Pipelines exposure due to erosion

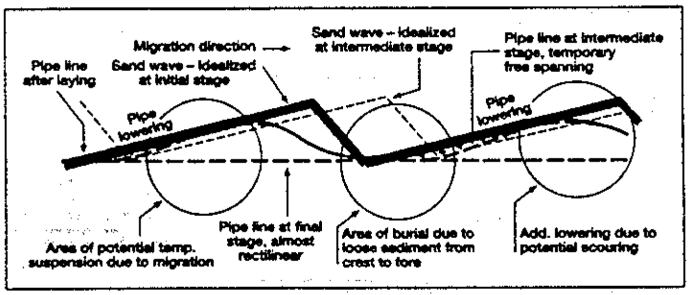
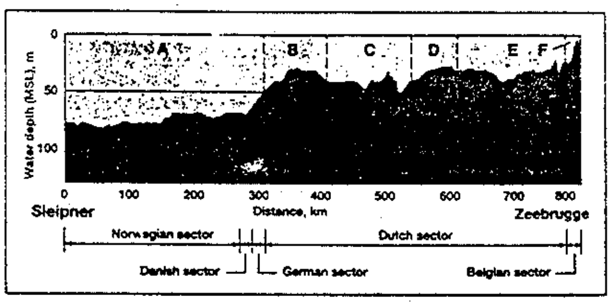


Fig. 4 - Schematic pipeline behaviour during sand wave migration



Zeepipe route features

Section A

- Seabed: Sandy
- Severe enviror. conditions (SEC): 0 – 150 km, H_s = 10 m; 150–310 km, H_s = 9.5 m
- Long term (LT) for Layable Concrete Coating (LCC): Stable pipe; 0 – 150 km, coating thickness (CT) = 80 mm; 150 – 281 km, CT = 90 mm; 281 – 310 km, CT = 100 mm
- Scour induced free spans (SIFS) in short & long term (S&LT): Yes; poss. self lowering in LT
- Burial criteria: None

Section B

- Seabed: Sandy
- SEC: H_s = 9.5 m
- LT for LCC: Unstable pipe; CT = 100 mm
- SIFS in S&LT: Not acceptable, self lowering in LT
- Burial criteria: Just after laying

Section C

- Seabed: Silty-sandy-clayey
- SEC: Less than A & B; H_s = 8.2 m
- LT for LCC: Unstable pipe; CT = 100 m
- SIFS: Yes; self lowering in ST
- Burial criteria: To be confirmed during 2nd const. season

Section D

- Seabed: Sandy
- SEC: Hs = 6.6
- LT for LCC: Unstable pipe; CT = 100 mm
- SIFS: Yes in ST and LT, poss. self lowering in LT
- Burial criteria: To be confirmed during 2nd const. season

Section E

- Seabed: Sandy
- SEC: H_s = 2 – 6.6 m
- Remarks: Sig. bedform activity, mega ripples & sand waves, free spans induced by BF activity & scour
- LT for LCC: Unstable pipe south of 775 km, CT = 100 – 110 mm
- Burial criteria: Both preparation & post-trench. in const. season

Section F (to landfall)

- Seabed: Silty-sandy-muddy
- SEC: H_s = 1 – 2 m
- Remarks: Extensive sediment transport with morphological modifications
- LT for LCC: Unstable pipe in LT, CT = 110 mm
- Burial criteria: Dictated by safety/authority requirements, both prep. and post-trenching done

Fig. 5 - ZEEPIPE - seabed profile and route features

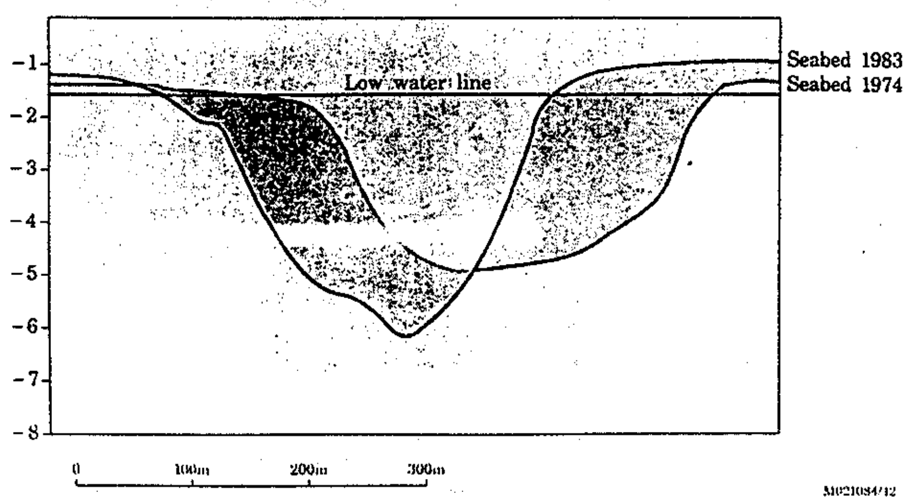


Fig. 6 - NORPIPE : Tidal channel profile variation (Nothern Lay)

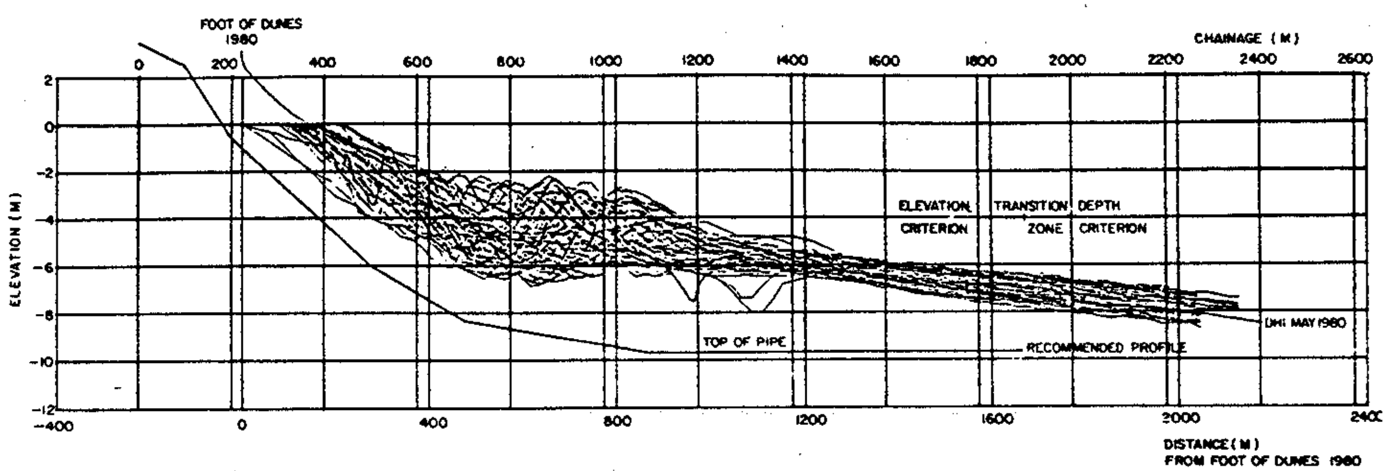


Fig. 7 - DONG : nearshore seabed evolution

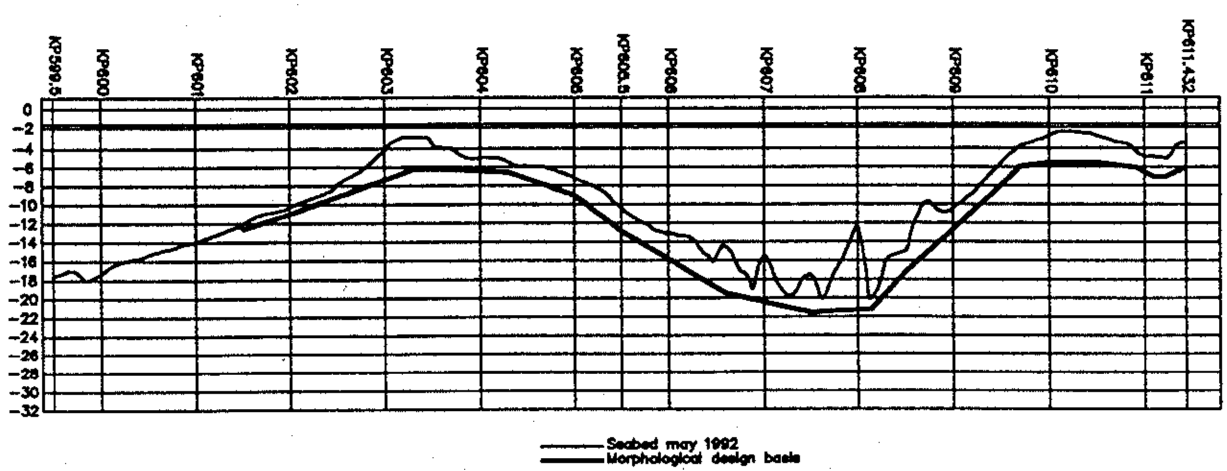


Fig. 8 - EUROPIPE : morphological design basis

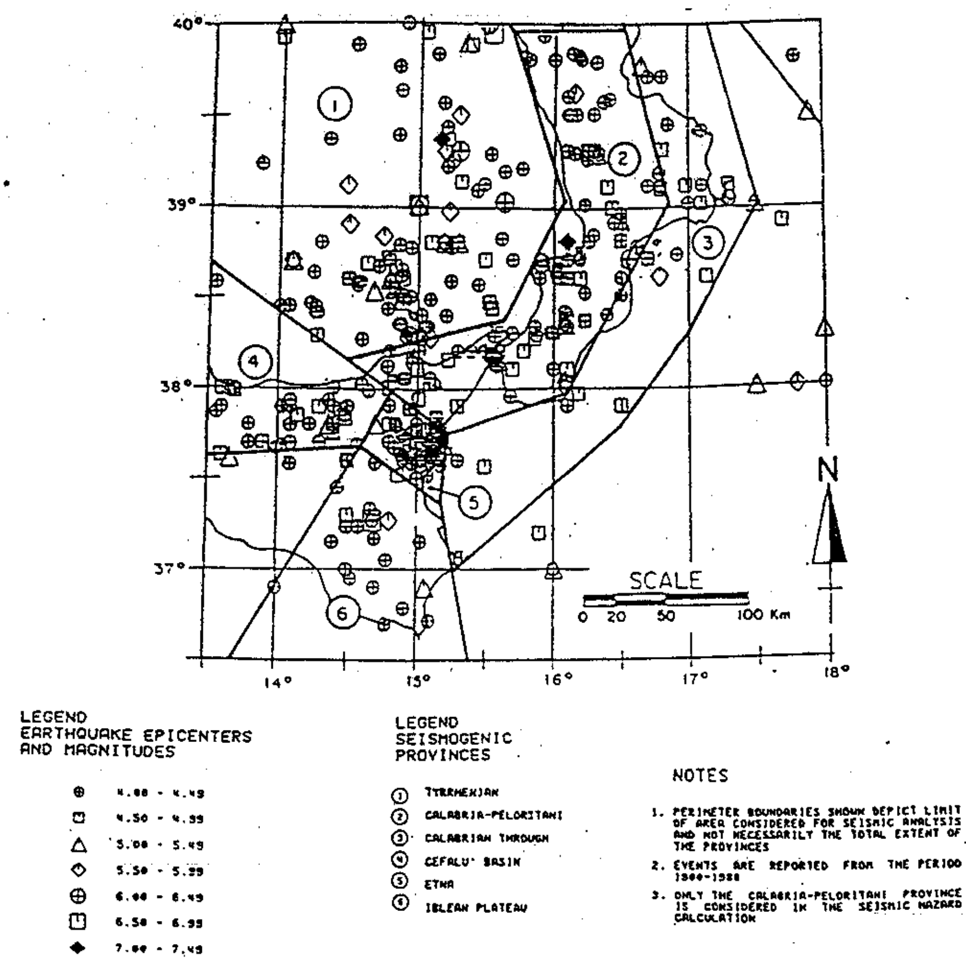


Fig. 9. Seismogenic regionalization

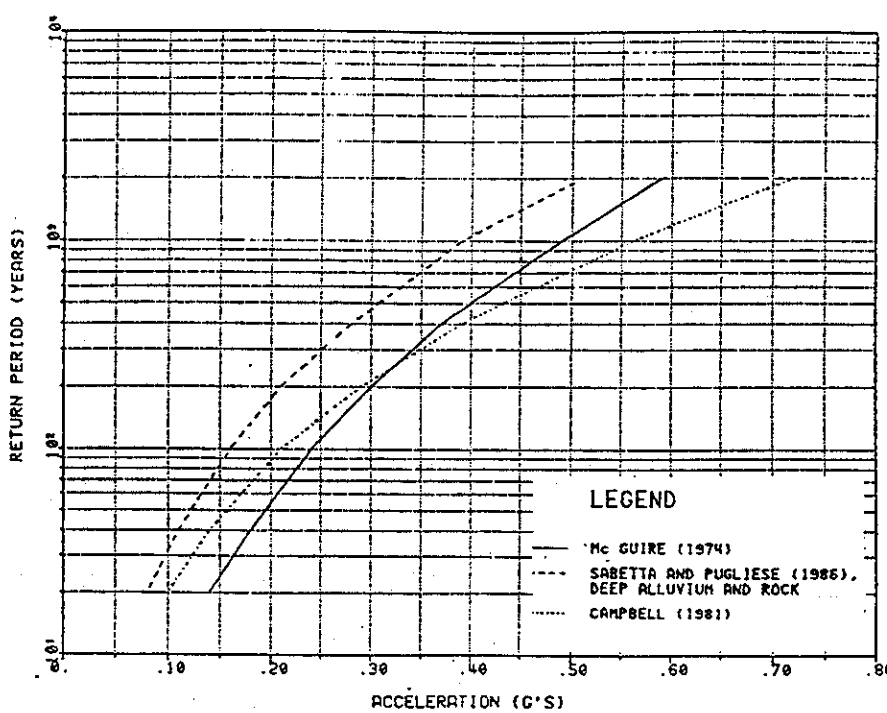


Fig. 10. Acceleration Vs return period for different attenuation laws

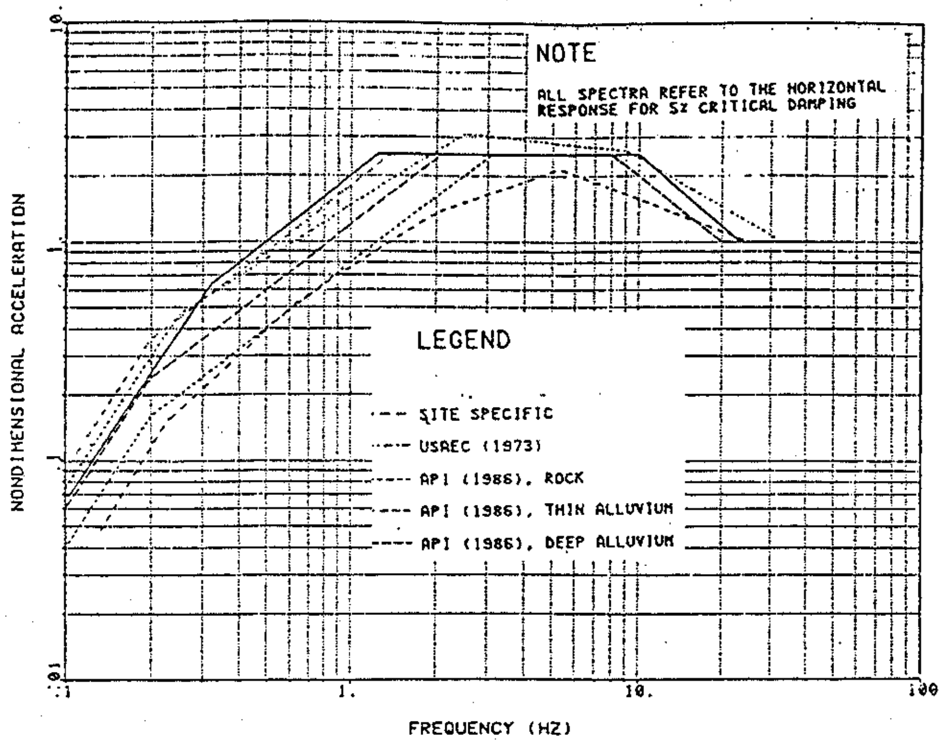


Fig. 11. Comparison of calculated-proposed response spectra

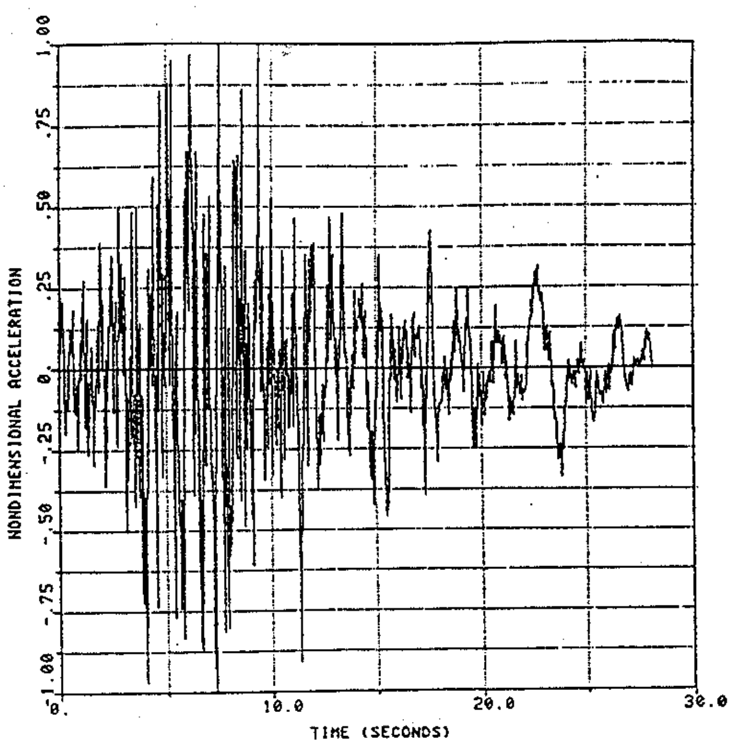


Fig. 12. Synthetic non-dimensional acceleration time history

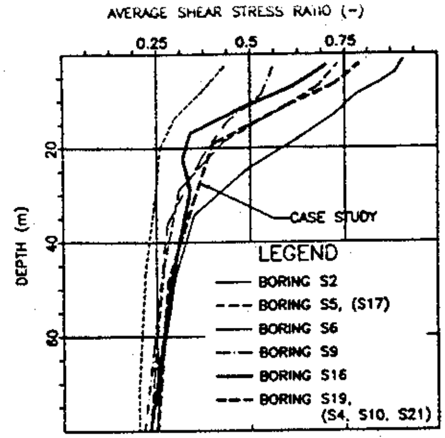
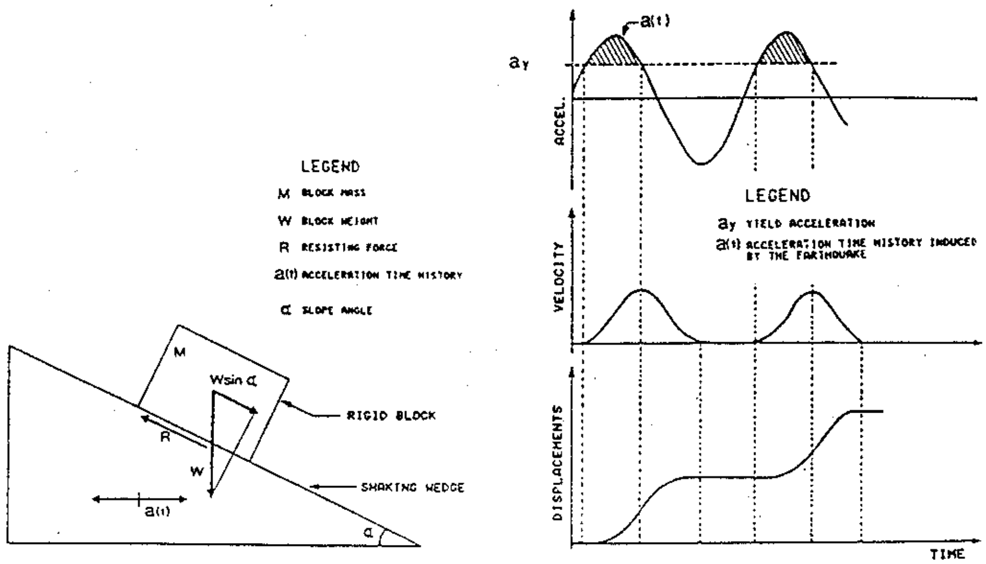
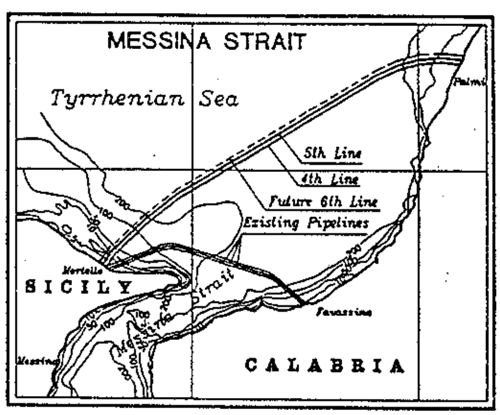


Fig. 13. Average shear stress ratios for the PLS seismic event



Fif. 14. Sliding block model and method to compute residual displacement



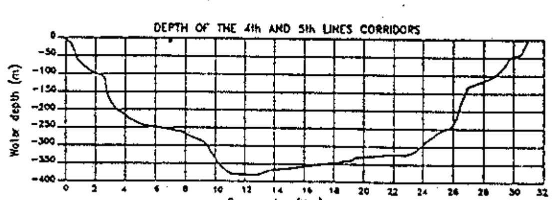


Fig. 15. Bathymetric profile and route of the new Messina Strait pipelines

KEYNOTE PRESENTATION III

"A DECADE OF INSPECTION FINDINGS COMPARED WITH DESIGN ASPECTS OF TWO NORTH SEA PIPELINES"

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Abstract

Dansk Olie & Gasproduktion A/S operates two pipelines in the Danish sector of the North Sea, both of which have now been in operation for 10 years. One is a 210 km. long 30" gas pipeline, which runs from the TYRA-East platform complex to the west coast of Denmark, and the other is a 220 km. long 20" oil pipeline, which runs from the GORM platform complex to the same location as the gas pipeline on the west coast of Denmark.

The dual landing of the pipelines at the west coast of Denmark is within an area which is fully exposed to the North Sea environment, and relatively large variations in seabed level, including moving sandbars, occur over time in connection with large sediment transport in the coastal zone. Prior to the construction of the pipelines, these variations were predicted in order to establish a safe burial depth of the pipelines. Over the following years the seabed movements in this area have been monitored by annual inspections.

Based on design considerations, the pipelines were trenched along their entire length to approximately 0.2 to 1 m. below the mean seabed at the time of the installation, and during the following years natural backfilling was estimated to take place and covered the pipelines over most of their length. However, after some years of operation, free spans started to develop at a number of locations along the pipeline route, and these have been assessed in order to identify possible explanations of the observed change in scour development.

Close to the TYRA-EAST platform a valve assembly protection cover (VAPC) consisting of a closed steel structure, has been installed over the pipeline, and scour protection has been applied by rock dump. Scour has however developed around the structure leading to accretion of rock over the valves, making access difficult. Hydraulic model testing has been performed in order to investigate whether opening up the structure by removal of parts of the cover plates would reduce the problem with rock accretion around the valves.

This paper describes the design aspects assessed for the pipelines related to the above problems, and makes comparison with the physical findings of the annual external surveys.

Introduction

The supply of gas to the domestic market in Denmark is produced in the Danish part of the North Sea. The gas is produced as associated gas from the oil production as well as from sole gas reservoirs. The present oil and gas transportation systems are illustrated in Figure 1. The gas streams are joined at the TYRA-EAST platform complex and transported through the 30" gas transmission line to shore over a distance of 215 km.. The oil and condensate streams are joined at the GORM field, and pumped through the 20" oil transmission line to the onshore terminal at the East coast of Denmark, a distance of 330 km. away. The gas pipeline includes a subsea safety valve with protection cover located 1.5 km. from TYRA.

Both pipelines were installed during 1982-83. They are made of concrete coated steel pipe, and were jetted down for the entire route from the coast to the platform, since stability analysis showed this to be necessary for protection against wave and current action in these relatively shallow waters. The maximum water depth is approx. 52 m.. During the following years most of the trench was naturally backfilled, and today there are only a few km. of exposed pipe distributed along the pipe routes. After the first 10 years of service, the pipelines have in general behaved as foreseen in the design. In some areas, however, unexpected problems have been encountered, and this has mainly been due to environmental loads, such as formation of free spans at a number of locations and scour around a subsea valve assembly cover.

On the other hand, there was great concern during the design phase about the risk of scour in the landfall area and the possibilities for free span development. As shown later in this paper, the design was able to foresee the impact from the environment and no tendency to pipeline exposure has been found in the landfall area..

Inspection and Maintenance Aspects of Pipeline System

The Danish gas supply is nearly entirely dependent on these two pipelines, and great efforts have therefore been put into not only the design, but also the inspection and maintenance in order to maintain the longterm integrity of these pipelines. A 5 year inspection program was therefore implemented from the first day of operation, and is adjusted every year, to take into account the findings of the annual surveys. A typical 5 year external inspection plan for these pipelines is as follows:

ACTIVITY - YEAR:	1	2	3	4	5
Side scan sonar	x	x	x	x	x
Sub bottom profiler	x				x
ROV inspection	x				x
Diving at VAPC	x	x	x	x	x
Echo soundings at landfalls	x		x		x

To give an overall status of the condition of the pipelines, a side scan sonar survey is performed in the beginning of each year. This gives information on exposures, free spans and on any third party activities in the pipeline corridor such as anchor scars and fishing activities. In case exposures have developed into free spans or if anchor scars are found close to the pipelines, this is later inspected in detail by divers or Remotely Operated Vehicle (ROV), as the side scan sonar can not give the same detailed information about free spans or see whether the pipe is damaged. Figure 2 shows a typical side scan sonar record of an exposure with free spans.

As the major part of the pipelines are buried, the burial depth is measured with a sub-bottom profiler. The first year of the survey showed that the seabed is relatively stable over most of its length, and the burial depth is therefore only checked every fourth year. The exposed sections of the pipelines are inspected by ROV on a regular basis every four years to check for damages, free spans, and to do cathodic protection measurements of anodes.

In the landfall area the position of the pipes relative to the seabed was checked by divers in 1984. Since then the seabed level has been checked only by echo sounding, as the pipe position appeared to be stable. This was done annually in the first years of operation, but is now reduced to once every two years. The valve assembly is inspected annually by divers. The divers check the structure for damages, measure the CP potential of the anodes and the exposure around the structure.

However the general problem with the above mentioned inspection methods, are that because they are done from surface vessels, they can only be performed in reasonably calm weather and do not reflect the situation during storms (which is the critical situation for a pipeline). This means that pipelines that appear to be buried or well supported during annual inspections, might develop into exposures or free spans during storms. To overcome this problem, it has been suggested that a so-called "burial and coating pig" might be the solution. This would run inside the pipe and be independent of the weather. It should be able to measure exposures, free spans, coating damages and to a certain degree the burial depth. It might however be difficult in practice to correlate the launching of a pig with a storm situation, as this would require the tool to be on stand-by for a long period.

<u>Landfall of Pipelines</u>

The dual landing of the North Sea 30" Natural Gas and 20" Crude Oil pipelines at the west coast of Denmark, is within an area which is fully exposed to the North Sea environment. Because of the extremely high longshore sediment transport in the area, the shore approach was a major challenge to the entire project.

The sandy coast has a wide beach with foredunes and inland dunes, and the appearance together with geological and historical evidence show that the beach at the landfall site has accreted and is now basically in dynamic equilibrium with equal long term supply and loss of sediments. During severe storms, erosion on the beach occurs in connection with a smoothing of the coast profile, and the foot of the dunes may recede as the sand is being carried seawards. Much of the eroded sand is usually returned to the beach by wave action after storms, and the coast profile is eventually restored.

The beach morphodynamics contain onshore bar migration and beach accretion (summer conditions), alternating with beach erosion and regeneration of the inner sandbar (winter conditions). Furthermore, the middle and outer sandbars generally move seaward during the winter and landward during the summer, following the variation in wave characteristics (wave size and steepness and consequent variation in breaking depth). The two pipelines were pulled ashore in a 1600 m. long common pre-dredged trench and into a sheet piled cofferdam across the beach. The trench had a volume of approximately 600,000 m^3. After installation of the pipelines the trench was left for natural backfilling.

To ensure that the pipelines in the shore approach area had sufficient cover for situations of extreme seabed fluctuation, a study was undertaken in order to predict the seabed variations and thus enable establishment of the safe burial and cover depth. Ten years of yearly coast profiling, at 1 km. intervals along the coast at the location, were used for this purpose.

The seabed low envelope was established using 10 adjacent profiles, located symmetrically around the landfall location, for each of the 10 years considered, using the foot of the dunes as a common reference point. The profile measurements represented calm weather conditions, and a storm erosion allowance of 1.2 m. was applied (in addition to the required minimum shore approach cover of 1 m. at all times). This was added to the low seabed envelope in order to obtain the top of the pipe profile, as shown in Figure 3 (which includes the seabed profiles above the pipeline recorded during inspections in the years 1982 to 1992).

The as-laid position was 0.5 to 1 m below the required level. The predredged trench was left to be covered by natural backfilling processes, and monitoring was carried out to check the progress of the backfilling process. Within the first year after pipeline installation, the backfilling of the trench was basically fully completed.

<u>Scour Development Along Pipelines</u>

Background

In the construction phase, the pipelines were trenched along their entire length between the shore approach and their respective platforms to a cover depth below the mean seabed of approximately 1 m. for the first 81 km. from the landfall, and 0.2 m. for the remaining route to the platforms. The trenching requirements were based on design considerations involving assessment of pipeline stability and protection aspects. The 30" gas pipeline was trenched concurrently with the 20" oil pipeline over two seasons, starting in June 1982, and the trenching operations were resumed in April 1983 and completed in August of the same year.

The pipelines in the trench were left to be covered by natural backfilling, and in the design study the backfilling rates were estimated based on the knowledge of environmental conditions and seabed soil conditions. In the prognosis it was estimated that throughout the inshore half of the pipeline and in the platform area, 90% of the natural backfilling was expected to take place within 10 months after trenching, and in the section west of the midway point the same was expected after 20 months. In the deepest part of the Helgoland channel, no significant natural backfilling was expected to take place. This expected absence of backfill was accounted for in the pipeline stability design.

During the first survey during operation in 1984, this was found to be a very conservative prognosis, as not only the platform area and the inshore half of the pipeline was found to be approximately 95% backfilled, but also the deepest part of Helgoland channel was mostly natural backfilled.

The 20" oil pipeline was found to be even less exposed than the gas pipeline, and no free spans have been found. The soil conditions are similar for the two lines, and the difference in the degree of exposed pipe can therefore be explained mainly by the higher specific gravity of the oil pipeline together with the lesser stiffness of the smaller oil pipeline than the gas pipeline. It would therefore be easier for the oil pipeline to follow the natural curvatures of the seabed, with less tendency to form free spans.

Scour and Free Spanning After Trenching of Pipelines

One of the exposures at the gas pipeline is located at km. 190 (measured from the landfall) and was found at the surveys in 1984 and 1985. During the survey in July 1988 a number of free spans were found at this location, and a study of the behaviour of the spanning pipeline, as well as a study of possible scour development at the location, was undertaken as this exposure included the longest free span found on the pipeline. Further scour studies of both the oil and gas pipelines were undertaken following the surveys in 1989 and 1991. The purpose of these studies was to establish criteria for development of free spans along the pipeline route, based on the experience from this exposure. It was hoped that the conclusions could be used to decide whether some of the other pipeline exposures might develop into free spans, and therefore should be protected against this by rock dumping.

At this location the water depth is 52 m., and the pipeline was trenched to a specified depth of 0.2 m. from the natural seabed to the top of the pipe. No engineering backfill was applied, and only limited natural backfilling was originally expected to occur at the location which is within the deepest part of the Helgoland channel. The soil conditions at the area of the location are described as layered clays, silts, and shallow marine post-glacial sand.

The surveys performed here in 1984 and 1985 showed that the top of the pipeline was exposed for approximately 70 m., whereas the neighbouring sections were fully covered (by natural backfilling). At the survey in July 1988 it was discovered that the pipeline had developed free spanning sections within an approximately 100 m. long exposed section. The longest span discovered had a length of 25 m. with other span lengths of 1, 6, and 7 m., as shown in Figure 4. The survey performed in 1990 showed a rather sudden acceleration in scour development compared to previous years. Exposure and free span lengths had increased in certain areas by 30% from 1989 to 1991. At this stage, as the length of the free spans was approaching the allowable length, further development of free spans was stopped by rock dumping over the entire exposure length.

Scour Development

Based on existing wave measurements in the nearby area covering the main part of the period in question, the scour development was assessed. It showed that the development of free spans at the considered locations requires relatively severe environmental conditions. The information from the survey and the environmental data available was not sufficiently detailed to determine accurately the limiting wave heights for which scour would be expected. However the indications were that the critical wave and current conditions would be in excess of a typical one year storm.

In terms of environmental conditions, the most important parameters that control scour development, are the KC-number together with the wave induced bottom velocity. Based on the existing wave data, the highest KC-numbers and near seabed velocities were determined for the various years, in order to evaluate the respective scour potential. A comparison showed that February 1988 and December 1990 did exhibit the most severe conditions for the period considered. This was in agreement with the observations made in the surveys in 1988, 1989, and 1991. Thus, the first observation of the free spanning at KP 190 was made in July 1988, after a very severe storm in February 1988. The survey in 1989 showed some limited development of the free spanning, whereas a very pronounced increase in the free span length was observed in the survey of May 1991.

Further Scour Evaluations

An evaluation was made based on KC-number and wave-induced velocity perpendicular to the pipelines, in order to evaluate the risk of continued scour.

Many parameters affect the development of exposures and free spans for otherwise buried pipelines. These parameters include soil type, trenching depth, and environmental conditions. The risk of exposures or free spans is therefore related to the sediment transport capacity of the location, as this is required in order to expose otherwise covered pipe sections. Growth of existing scour holes requires removal of sediment from the area near the pipeline, and the net sediment transport will therefore be a good measure for the likelihood of scour. The propagation or increase of scour holes along a pipeline, however, is more likely related to the gross sediment transport rather than the net transport.

Figure 5 shows the criteria for onset of sediment transport as calculated for different positions along the gas pipeline, for one grain size and two values of steady current, and as a function of significant wave height. The figure shows that the onset of sediment transport (and furthermore the relative largest amount of net as well as gross sediment transport) occurs most often nearest to the shore, as transport here occurs for the lowest wave heights.

In fact the minimum sediment movement and transport occurred around positions 170 to 190 km., and this is where some of the free spanning has occurred. This appears to be in contradiction with the basic hypothesis that the development of exposures can be related to the sediment transport rate alone. Other conditions or phenomena must therefore be incorporated for the identification of sections susceptible to free span development. These may include the presence of silt, longterm fluctuations of the seabed (e.g. migrating sandwaves), and the initial as-built burial depth. However it was not possible to establish more accurate reasons for the development of exposures and free spans in the time frame of the evaluations carried out here.

Valve Assembly Protection Cover

Background

During the design phase it was decided to construct a subsea safety valve system on the 30" gas pipeline, approximately 1.5 km. SE. of the Tyra East platform. This decision was based on safety studies, and the aim was to reduce the risk of explosion or suffocation at the nearby platform, while at the same time preventing loss of gas, and minimizing outage time in connection with repair work in the high risk zone near the platform.

The subsea safety valve system basically consists of a check valve and a full bore ball valve, both manually diver operated. The system is protected against impact from dropped objects, fishing gear etc. by a Valve Assembly Protection Cover (VAPC), which consists of a pile supported enclosed steel structure shown in Figure 6. The water depth at this location is 38 m.. The check valve is located upstream of the ball valve, and the check valve closes immediately in case of flow reversal due to a rupture between the valve and the platform, thus separating the downstream 210 km. pipeline section from the ruptured section. The ball valve provides a backup for blocking the downstream gas pressure in case of a rupture.

Observed Scour Development and Remedial Action

The VAPC was installed in June 1983. One week after installation significant scour had already occurred underneath the sides of the structure. The scour holes were immediately repaired by filling with sandbags, and scour protection mattresses were fitted to the structure. However, a survey in November of the same year revealed that the mattresses were displaced and missing, and that initial scouring had taken place at that time.

By June of the next year, the scour had developed into a total underscouring of the VAPC, as well as the pipeline, which was found to be freely spanning at the VAPC, as shown in Figure 7. The free span was initially stabilised by positioning pipeline supports at the VAPC. Protective rock dumping was then carried out in November 1984, with the aim of establishing a stable seabed and providing a permanent remedy. The specifications for the rock dumping are illustrated in Figure 8. However a later survey in May 1985 showed that significant scour had subsequently developed anyway, despite the rock dumping, and that a massive layer of material had been deposited inside the VAPC, covering the check valve and thus hampering access to this valve. The situation is depicted in Figure 9 (the solid lines denoting seabed surface along the sides of the VAPC, and the dashed lines denoting seabed surface along the pipeline inside the VAPC).

After 1985 the scour under the coverplates has continued, and the rock dump material covering the valves has been removed with great effort by divers, in connection with maintenance and repair of the valves. Figure 10 shows the scour configuration as it appeared during a survey in the summer of 1989 (the solid lines again showing the seabed surface along the sides of the VAPC, and the dashed lines showing the seabed surface along the pipeline inside the VAPC). The bathymetry of the nearby seabed is also shown in Figure 11, based on an Ulvertec scanning survey carried out in July 1989.

Flow characteristics and scour mechanisms

The flow characteristics under normal conditions is mainly influenced by the tidal current, whereas for storm situations wave generated flows dominate. These can act together with the additional possible influence of storm surge generated current. Wave-induced velocities occurring under storm conditions are much higher than the velocities associated with either tidal currents or storm surge generated currents.

The scouring effect of steady current also differs from that produced by wave action. While the steady current is able to provide continuous transport of eroded material, the wave-induced flow is only able to carry eroded sediment back and forth to an extent limited by the flow amplitude. Accordingly, no significant removal of sediment from the VAPC is likely to be caused by wave action, but only a redeposition to calmer places like inside the VAPC.

The flow disturbance caused by the VAPC structure, and the associated nearbed increase in scour potential, depends among other things on the angle of approach of the flow relative to the VAPC. The situation is different when underscouring already exists, as compared to the situation without underscouring.

The flow at the structure is in general characterized by flow separation behind the sharp edges of the VAPC, leading to formation of corner eddies, and the presence of a more or less pronounced downstream wake. For smaller amplitudes of wave motion, the downstream wake may be fully absent. The eddies at the corner and downstream wake are most pronounced for the steady current case, and for the case of a closed structure. For the closed VAPC, the scour potential associated with corner eddies is significant, as is well known for other structures like bridge piers.

If a significant degree of underscouring exists, the general flow pattern changes. The eddies at the corners will gradually lose their scour potential once the underscouring progresses, due to their loss of contact with the seabed. With space established under the edges of the coverplates, tunnel erosion is liable to develop, due to the high flow velocities associated with flow amplification (which can be a factor of 2 to 3 relative to undisturbed flow) in the gap beneath the cover. Inside the VAPC the flow velocity then drops as a result of the expansion of the flow field. The resulting reduction of scour potential may then result in net deposition, typically of rock dump material, at the middle where the valves are located.

Model tests

The problem with the accretion of rock material at the valves was accentuated by the fact that the valves had been lowered some distance into the seabed, in consequence of the earlier occurred free spanning of the pipeline. Furthermore access to the valves for inspection and maintenance is required approximately once per year, to service the ball valve and to open the check valve manually prior to pig passage.

To study this problem better, scour model testing was undertaken by the Danish Hydraulics Institute. The main purpose was to investigate whether opening up the VAPC structure by removing the lower half-part of the plates, would reduce the problem of rock accretion around the valves. Furthermore it was of interest to see whether it was possible to reproduce the scour and deposition situation observed in the field. Accordingly tests were carried out in the following order:

a.) Existing VAPC on sand bed
b.) Existing VAPC on sand bed with scour protection (rock dump)
c.) Modified VAPC (lower cover plates removed) on sand bed with scour protection

A diagram of the test facility is shown in Figure 12. The validation tests were aimed at reproducing the observed scour and material deposition in the field, for the situations immediately prior to, and after, remedial rock dumping. Relevant wave and current conditions were applied, with angles of approach both parallel to and at 45 degrees of either side of the pipeline (corresponding to waves and current coming from the North West, West or North).

It was possible to reproduce scour and deposition conditions in good agreement with the prototype conditions, except for some minor differences which can be ascribed to the one-dimensional wave testing used, as opposed to the cumulative effect of different wave directions in the prototype. Figure 13 illustrates the scour configuration obtained in one of the test runs. Figure 14 illustrates one of the validation test runs, and Figure 15 shows the subsequent effect of removal of the lower half-part of the cover plates.

The tests with the modified VAPC (case c.) were performed immediately after the corresponding tests with the existing structure (case b.), so that the effect of the modification could be specifically isolated. These tests showed that the existing scour holes below the edges of the VAPC were backfilled, and the rock and gravel accumulations in the centre were to some degree levelled out, resulting in a relatively even area level with the natural seabed. As further evidence of this, a small excavation around the valves (corresponding to a full scale volume of 15 to 20 m^3) was performed after general levelling of the seabed, and this was partly backfilled in subsequent testing.

Based on interpretation of these test results, it was concluded that the removal of the lower part of the coverplates as an isolated step, would not eliminate the need for continued removal of stones around the valves. A significant amount of rockfill is present under and near the VAPC, providing material for filling local depressions. Accordingly, stones may accumulate to the top of the pipeline, and thus cause the valves to be partially covered. Continued removal of stones around the valves may gradually reduce the need for further stone removal, but it is not possible on the basis of the model tests to state when (or how) sufficient material will be removed.

As these test were not conclusive on the effect of removal of the lower plates, it was decided not to do any modifications of the VAPC. Since these tests were performed in 1990, the annual inspections have shown a reduction in the accumulation of stones over the valves, probably because most of the stones close to the structure have now been removed.

Conclusions

Based on the first ten years of service, the original design for the two Danish North Sea pipelines has proved to have been a success, and only a few unexpected incidents have occurred. The landfalls on the west coast of Denmark are in areas where large variations in seabed level were predicted. These predictions have been confirmed by the annual surveys. However, until the landfalls have been inspected during a storm situation, for example by a burial pig, it is not possible to know whether the pipelines have a satisfactory cover.

The observed development of exposures and free spans in the field has been more difficult to explain. The largest and greatest number of free spans has been found in the deepest water. This is in contradiction to the usual hypothesis, which relates the development of exposures to the sediment transport rate, which in turn should decrease with increasing water depth. It will therefore be necessary to monitor future development of exposures and free spans. Like the landfalls, such inspections should preferably be carried out during or immediately after storm conditions.

The occurrence of scour around the valve protection cover was significantly underestimated in the original design. Subsequent model tests have shown that, because of the peculiarities of this structure, there is no easy solution to the problem of continued scour around the structure and subsequent stone accretion over the valves. The tests have shown, however, that a more open structure would reduce the amount of stone cover.

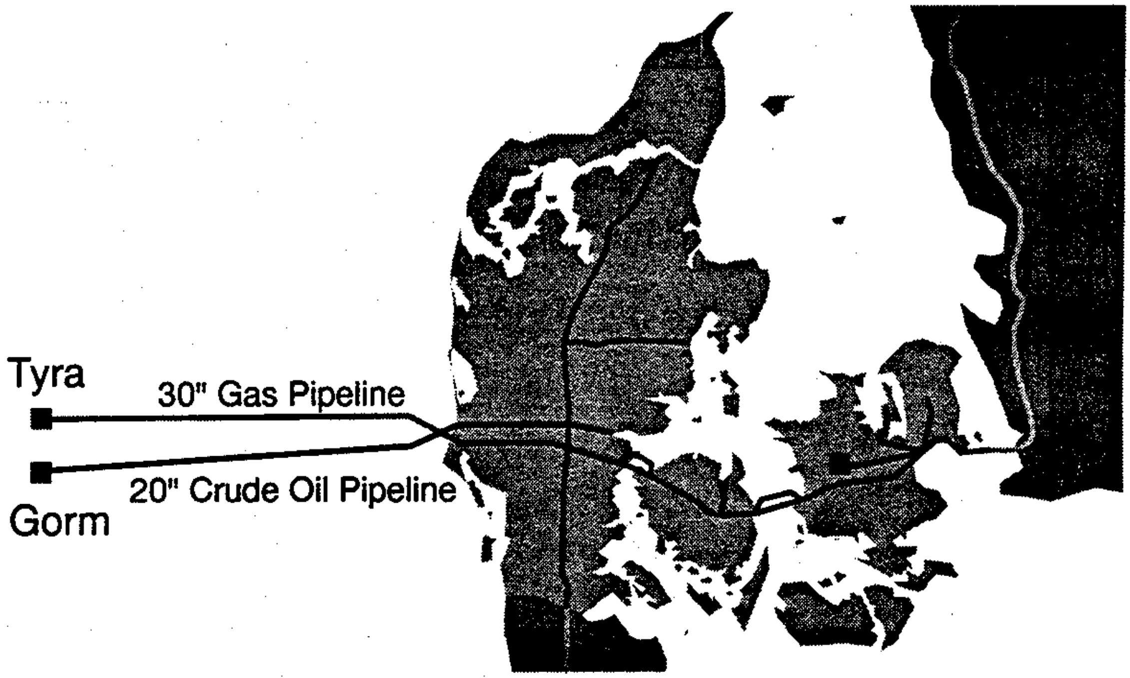

Figure 1 - Danish Oil and Gas Pipelines

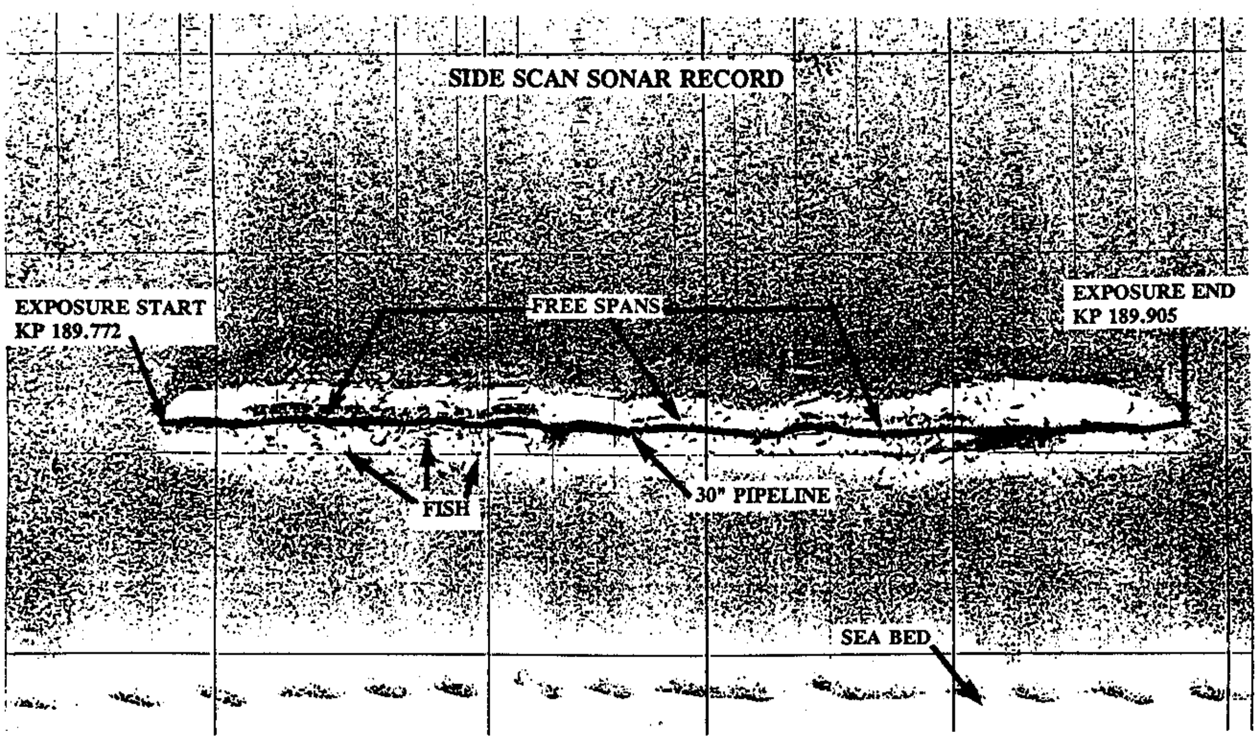

Figure 2 - Side Scan Sonar Record

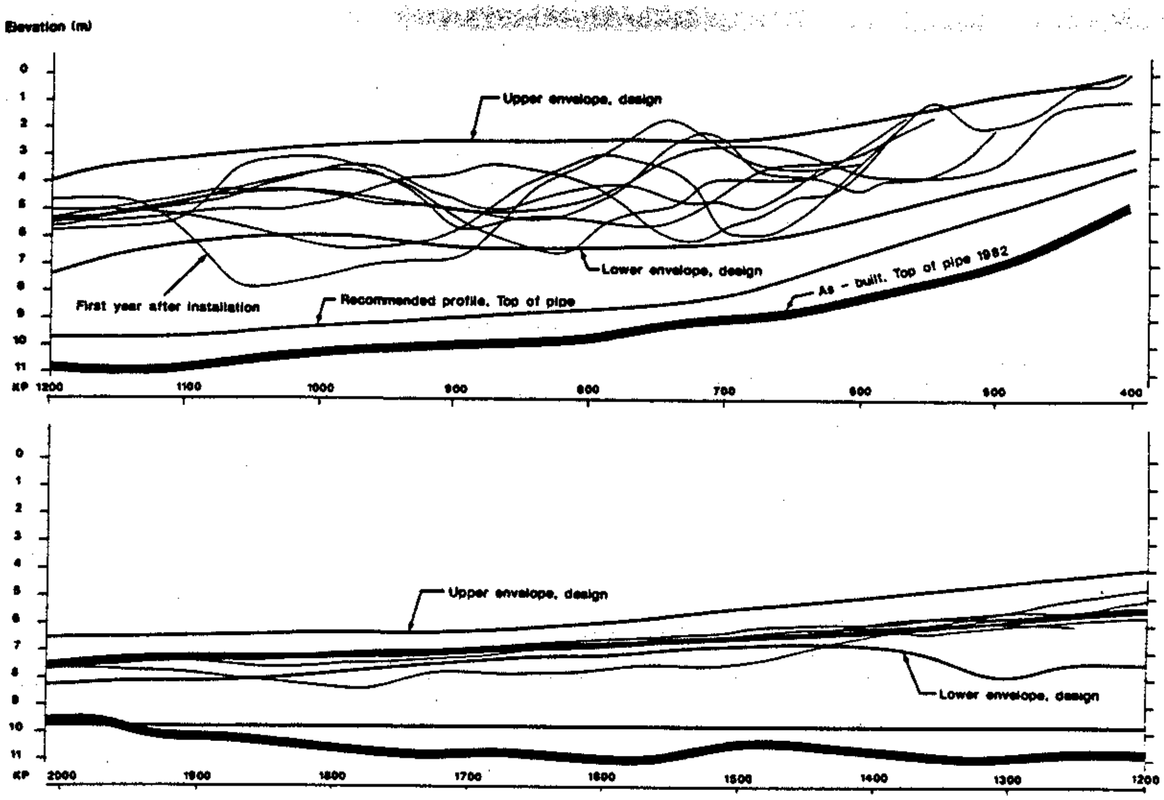

Figure 3 - Seabed Variations and Top of Pipe Profiles

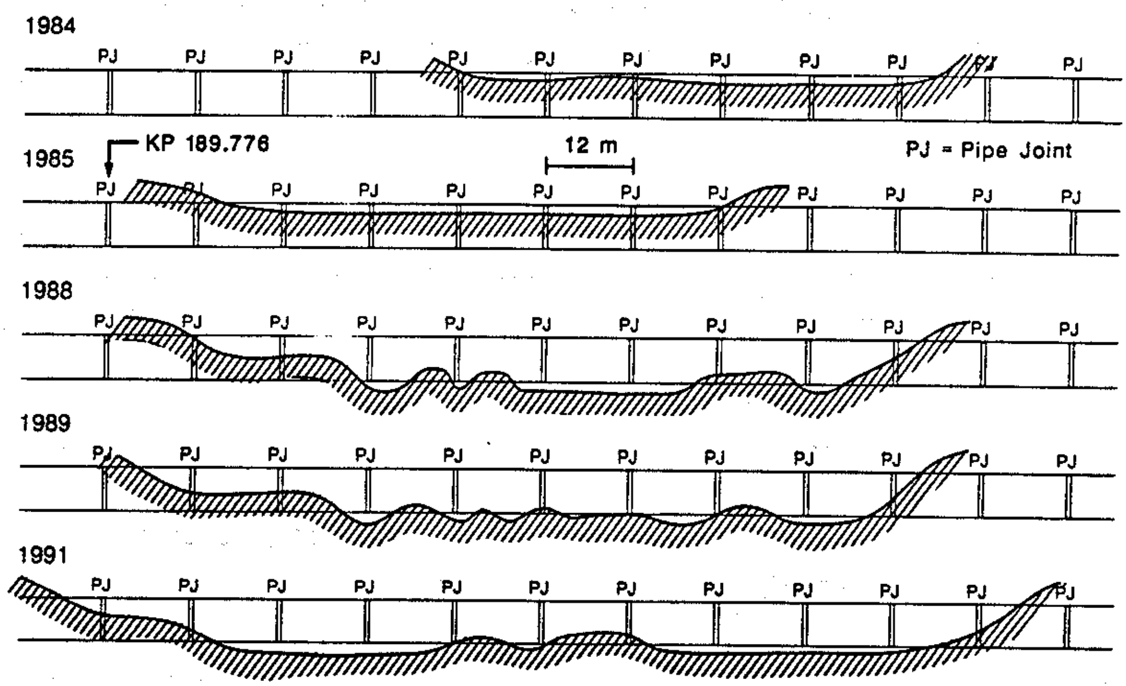

Figure 4 - Survey Findings, Exposed Gas Pipelines, Km. 190

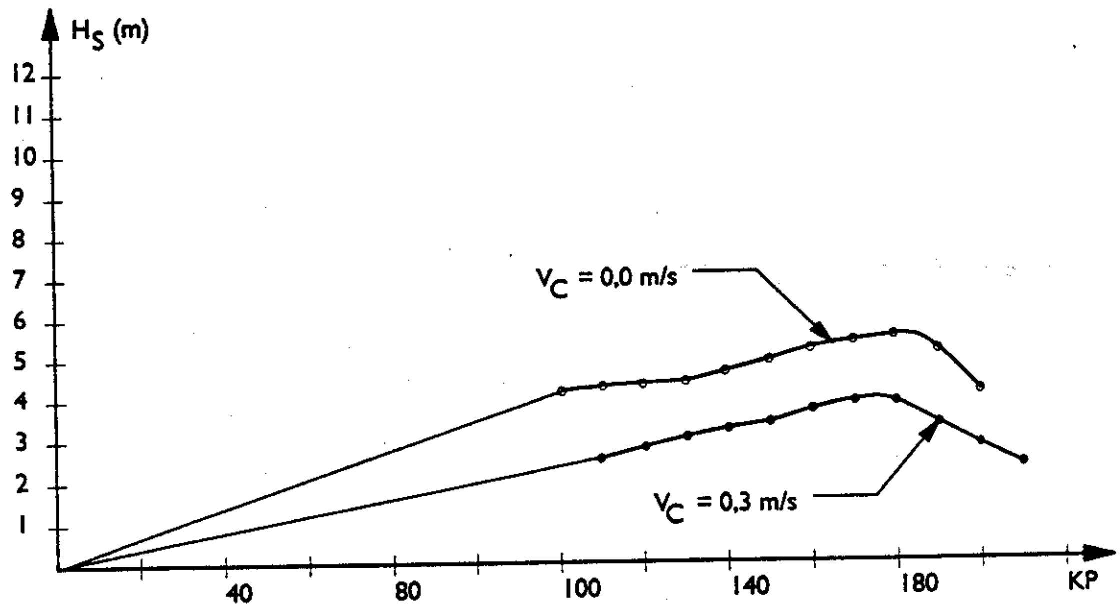

Figure 5 - Wave Heights for Initiation of Sediment Transport, along Pipeline

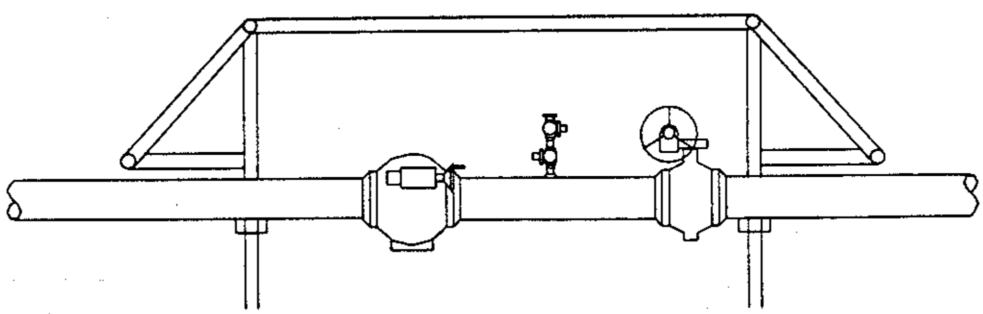

Figure 6 - Valve Assembly and Protective Cover, 30" Gas Pipeline

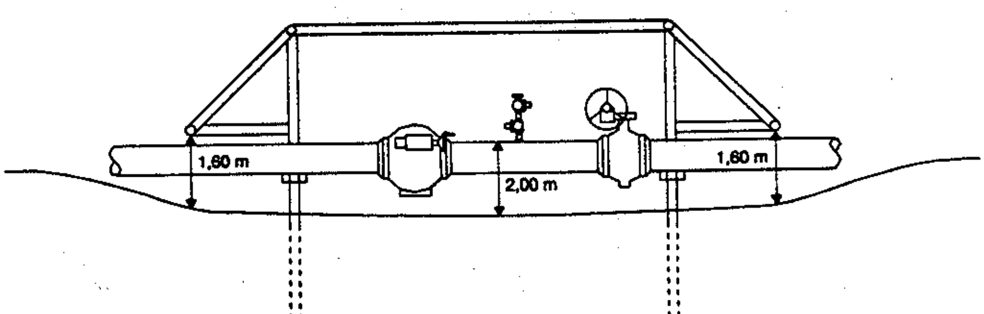

Figure 7 - Underscoured VAPC Prior to Protective Rock Dumping

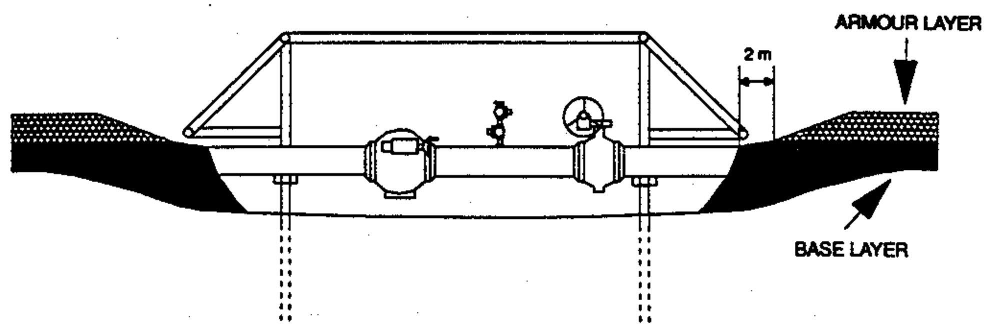

Figure 8 - Specifications for Protective Rock Dumping

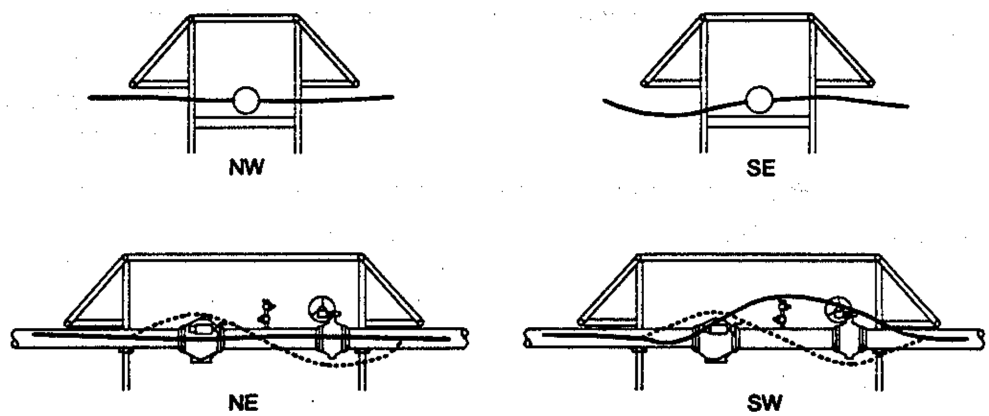

Figure 9 - Scour and Rock Accretion Observed in Summer 1985

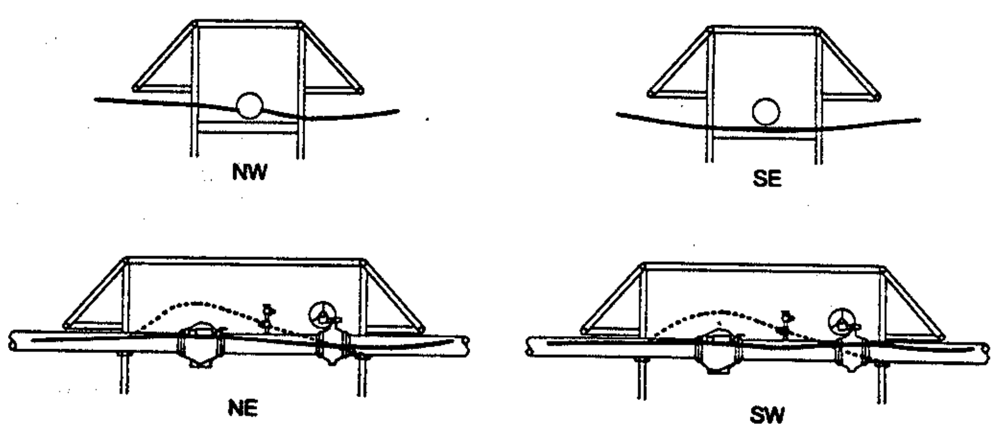

Figure 10 - Scour and Rock Accretion Observed in Summer 1989

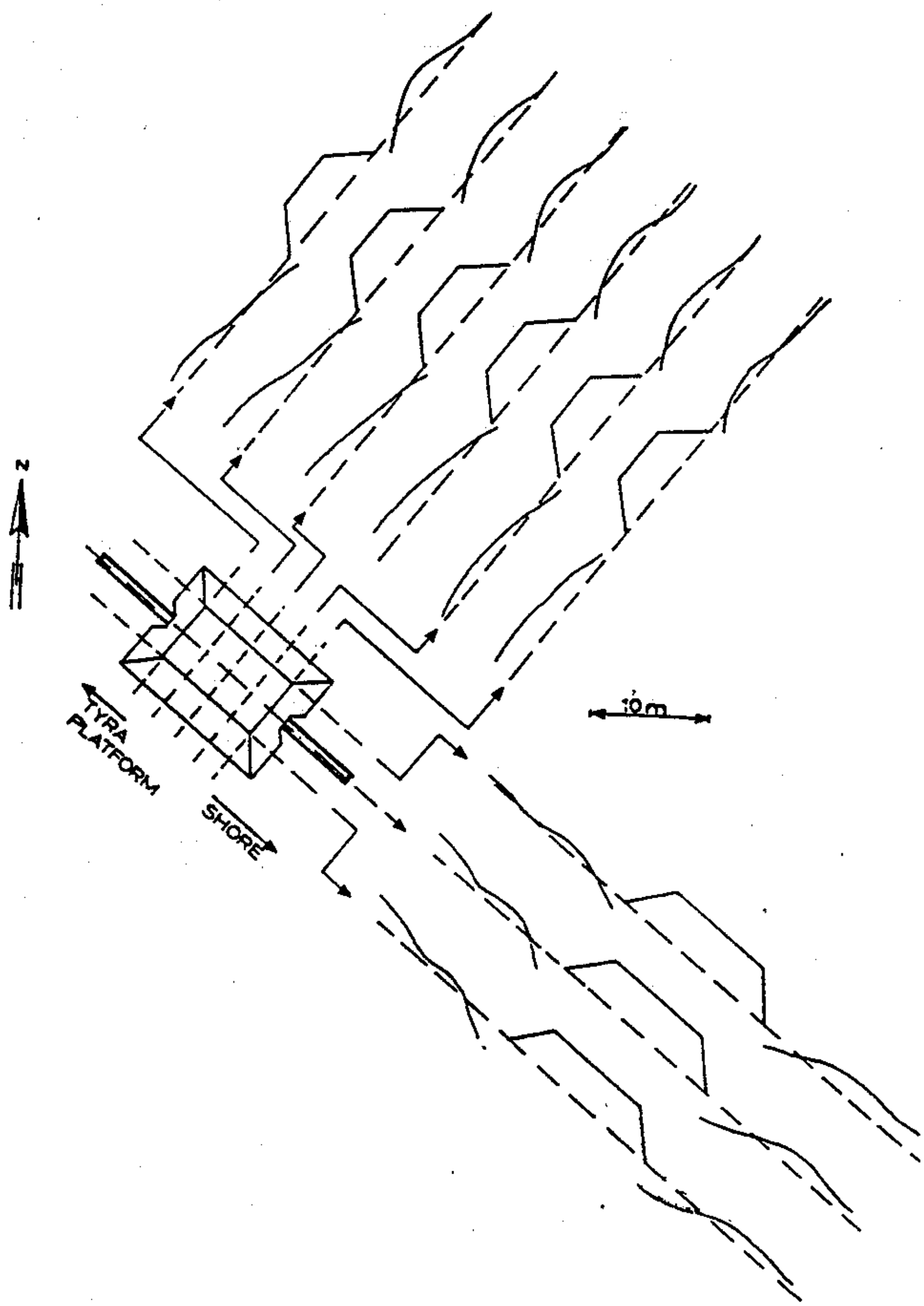

Figure 11 - Bathymetric Conditions Near VAPC, July 1989

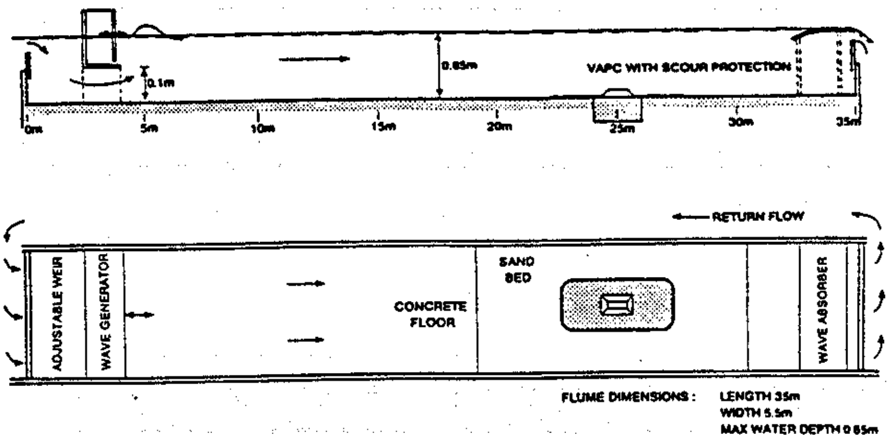

Figure 12 - Test Facility for Scour Model Testing

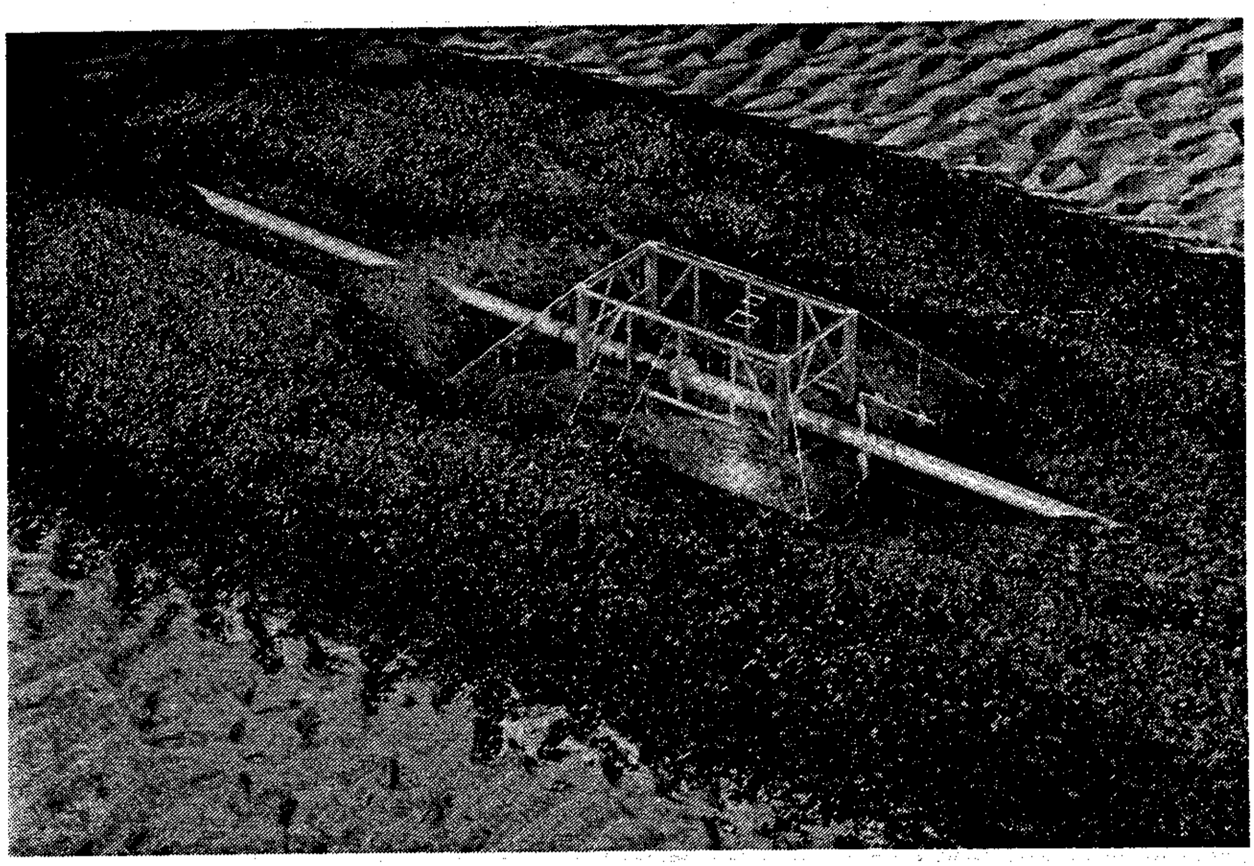

Figure 13 - Scour Configuration, Model Test

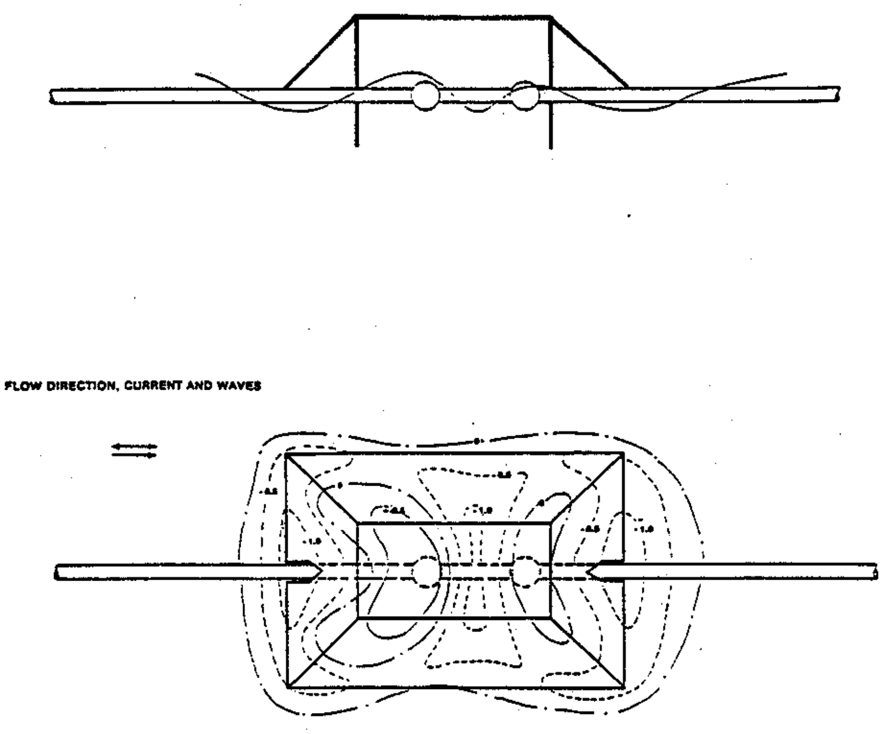

Figure 14 - Scour Configuration, Model Test Validation of VAPC

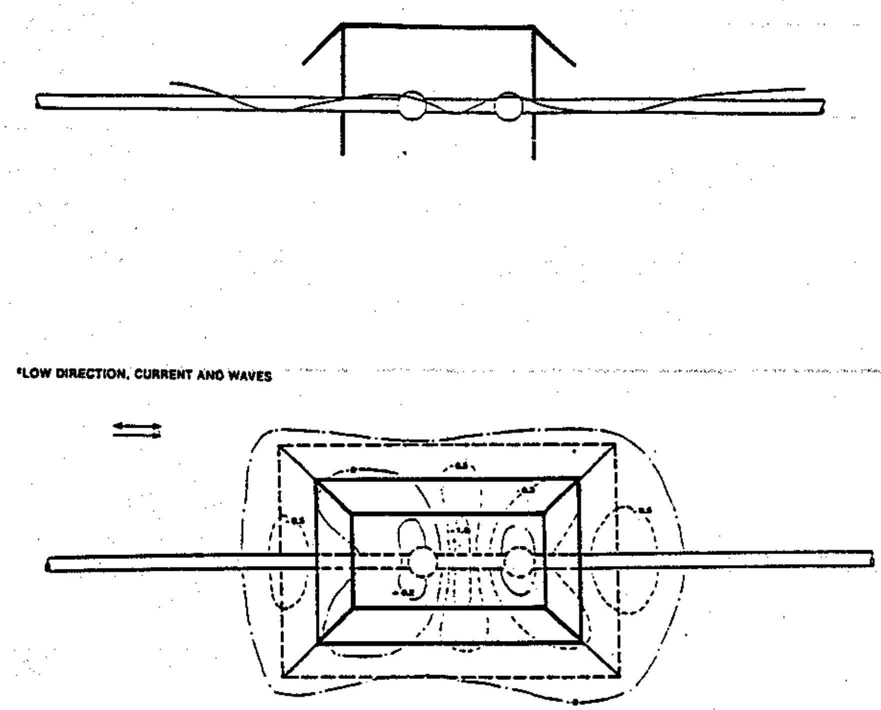

Figure 15 - Scour Configuration of Modified VAPC

KEYNOTE PRESENTATION IV

"HURRICANE ANDREW ASSESSMENT - SAFETY AND POLLUTION CONTROL DEVICES"

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J.P. Kenny International
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Introduction

Hurricane Andrew moved through the central Gulf of Mexico on August 24 & 25, 1992 with substantial damage to oil and gas platform mounted facilities in its path. The purpose of this presentation is to review and comment on information collected on behalf of the MMS associated with the performance during the storm of safety and pollution control systems utilized by offshore oil/gas operators.

Background Information and Data Summary

Hurricane Andrew was a Category 4 storm with winds at 160 mph and 65 - 70 foot maximum wave heights. The storm moved through the central gulf with the major damage occurring in a 75 mile path through a zone including the Ship Shoal and South Timbalier areas, as shown in Figure 1. The impacted area included 2000 movable and stationary platforms of which 800 were full fixed facilities. The damage reported was as follows:

Platforms - 36

Pipelines - 454

Fire - 2

Pollution (oil) Spills - 11

Although the damage to platforms in the path of the hurricane was significant, in reality less than 5% of the fixed structures in the path of the storm were impacted, and of that group, 70% of the total with significant reported damage were built before 1971 to less stringent wave design criteria than generally used today. The performance of safety and pollution control devices, as analyzed for the MMS study, can be related to the reaction of offshore support structures when line ruptures or system damage (and consequent failure to operate as intended) occur as a result of structural damage. A typical logistic diagram for offshore safety systems is shown in Figure 2.

It should also be recognized, in connection with the safety and pollution control devices considered, that with current storm monitoring and prediction capability, most offshore operators would have ample opportunity to shut down operations in advance either remotely or locally. However, it can be implied that the survival of safety and pollution control systems intact could interpreted as an operable system that would have functioned as intended.

Survey Criteria

J P Kenny was commissioned by the Minerals Management Service to survey operators in the storm impacted area concerning the performance of safety and pollution control systems (safety systems), with the purpose of analyzing the performance of the systems and developing recommendations for future facility operations. At the time this paper was presented, the work associated with the assignment had not been completed. However, the data gathering and analysis was complete, allowing the following summary of results to be presented.

Criteria used to evaluate offshore oil and gas safety systems include:

Safety - Associated with fire, wave and mechanical forces

Availability - Expressed as a percent of total operability

Mechanical Reliability

Protection - Personnel, the environment and facilities

Specific questions considered by this analysis are currently as follows:- are the 1971 and earlier designs for structures and safety facilities in the Gulf of Mexico adequate; is there a need to re-examine the methods and equipment for the future, particularly the surface portions of deep water oil and gas production facilities now in operation and on the drawing boards; and are human factors being adequately integrated into the process of maximizing safety while at the same time striving to improve the operability of offshore oil and gas structures and facilities.

Offshore Safety and Shutdown Valves Considered

The initial emphasis in the MMS study were the performance of safety, block and check valves, including ball (plug) and gate valves with operator, and gravity operated check valves as utilized by pipeline operators. Specifically, integral parts of the mandated safety systems included well head valves located in the well bore, on the tree, platform riser, and non mandated, but frequently utilized in world offshore areas, sub-sea ESD and check valves (FSV). Offshore safety and shutdown valves actuated for Hurricane Andrew are shown in Figure 3.

Preliminary Findings of Reported Malfunctions

Forty-four companies operating in the path of Hurricane Andrew were canvassed to obtain safety system operating experience during the period of storm impact. One third of operators responded with storm related data and information. In terms of safety valve failures, the South Timbalier area was the most impacted with 5 failures of a surface tree valve reported, all from a single incident associated with the structural failure of a caisson in production service. Closure of 12 subsea well bore safety valves were reported in the Ship Shoal and South Timbalier areas. The results also indicated that in excess of 2.6 thousand safety valves associated with canvassed well and pipeline operations were safely shut down in advance of the storm and satisfactorily survived the impacts of the storm surge and related structural movement.

In terms of pipeline response, surface shutdown and check valves and sub-sea ESD shutdown systems, performance in the storm was satisfactory with no failures reported or known from news or other reports. As reported in a recent study by the National Academy of Sciences, the primary cause of failure (95%) where product release occurs (pollution) is due to vessel damage and the 11 largest spill incidents resulted in 98% of pollution volumes.

Damage to pipelines included excessive movement, separation from structures, buckling, and puncture. Action of pre-installed break away joints, although requiring repair, demonstrated the value of these systems particularly in mudslide areas. Although not the subject of this presentation, storm related pipeline failures in terms of total failures constituted the main source of damaged oil and gas facility components.

Findings and Recommendations for Pipelines

In terms of components used for pipeline safety valve systems, various well known valve components are commonly utilized. Figure 4 shows different design options available for surface controlled subsurface safety valves. It has been found that gate valves are suitable to 8" size, and represent positive shutoff capability. Installation size for gate valve sizes over 8" becomes a deterrent to their use offshore where weight and space requirements are limited. Ball valves are satisfactory through all ranges, but generally lack positive shutoff. Check valves are a good first line passive safety component, particularly in sub-sea applications, but lack positive shutoff and can represent an impediment to normal pigging operations associated with offshore pipelines.

Actuators of safety valve systems include a number of alternatives. The hydraulic actuator develops the quick response required for most applications.

Reliability of safety valve systems components, particularly sub-sea (a source of concern to operators), can be improved by installing valves in parallel. Parallel installation results in a reduced probability of failure (35%) and typically translates to unscheduled outages of 2 days in the 20 year design life span of a shutdown system. Reliability can be substantially improved with scheduled testing of components. Recently developed subsea valves, both the check and plug type, can be repaired in place. Figure 5 shows a typical arrangement.

As mentioned above, there are no statutory requirements mandating the use of sub-sea emergency shutdown systems for offshore oil and gas operators. Many operators in the Gulf of Mexico and in other offshore areas, have begun to install sub-sea valve systems for this purpose, particularly where exiting gas pipelines exist, with the goal of mitigating the effect of pipeline leaks inside an envelope including the platform, production and area pipeline facilities including the riser system.

For existing systems, particularly those systems built before 1971, retrofit of sub-sea shutdown facilities in pipelines, could be an effective way to improve safety and reduce potential pollution impacts, where projected production rates justify the effort.

For all facilities offshore, and particularly facilities installed before 1971, implementation of operation programs emphasizing safety and prudent operations are extremely important - even if, for example, additional shutdown facilities over and above those already existing as suggested above are not installed. The most important component of any offshore oil and gas system are the operations personnel. Training and upgrading of field operations personnel must be at the top of the list of any program to improve safety awareness and equipment operations, and mitigate the effects of offshore impacts both natural and man related. Effective implementation of the pipeline safety programs already mandated, will result in improved safety and profitable operations.

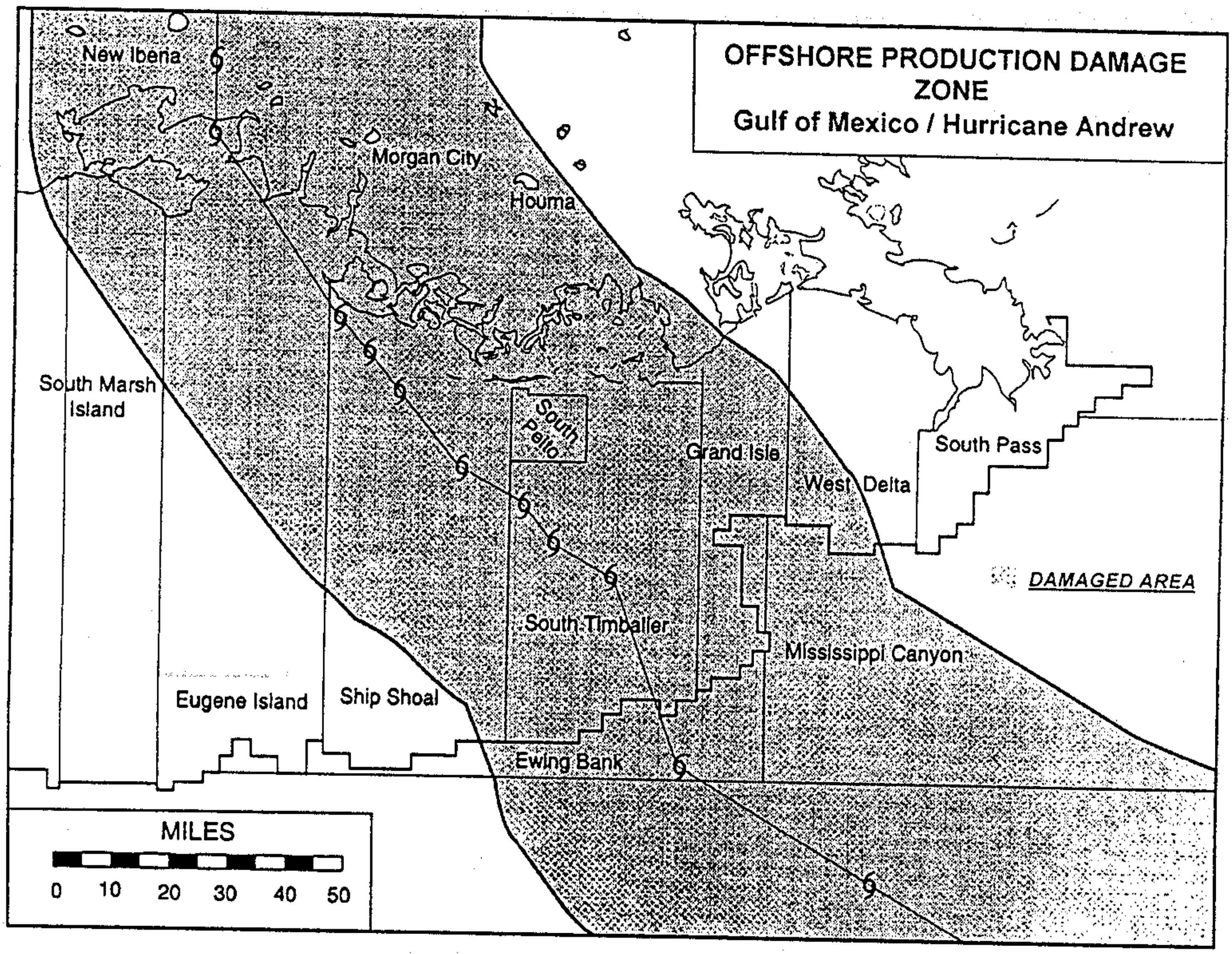

Figure 1 - Area of Hurricane Andrew Damage Survey

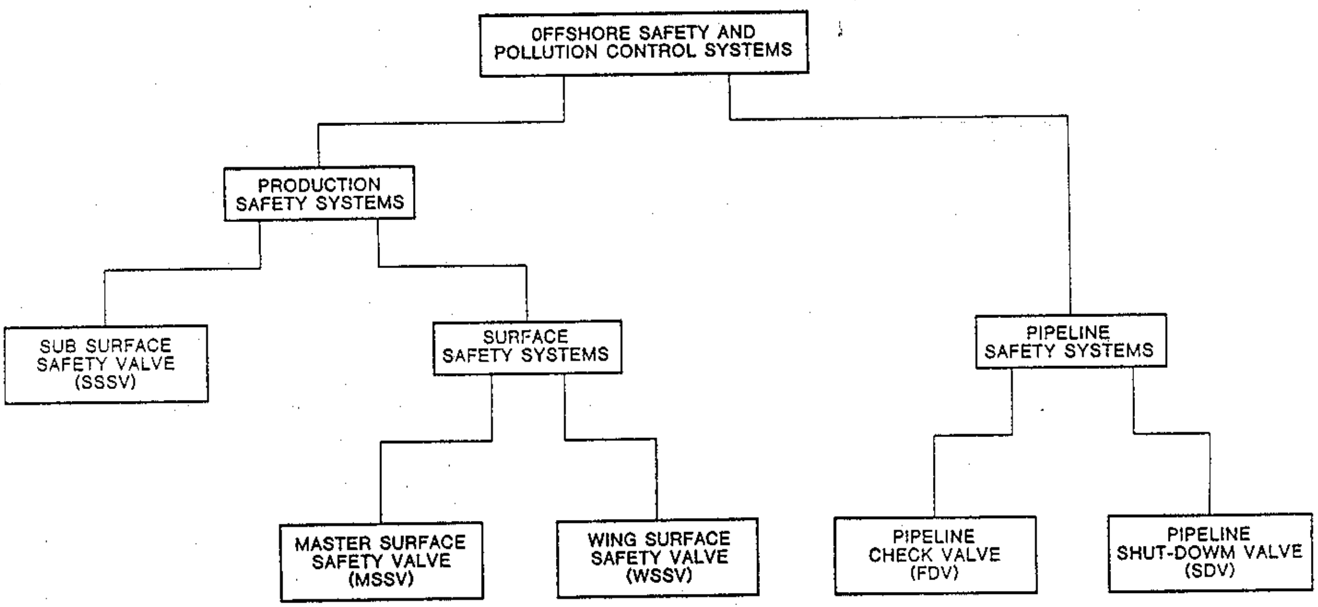

Figure 2 - Logistic Diagram of Offshore Safety Systems

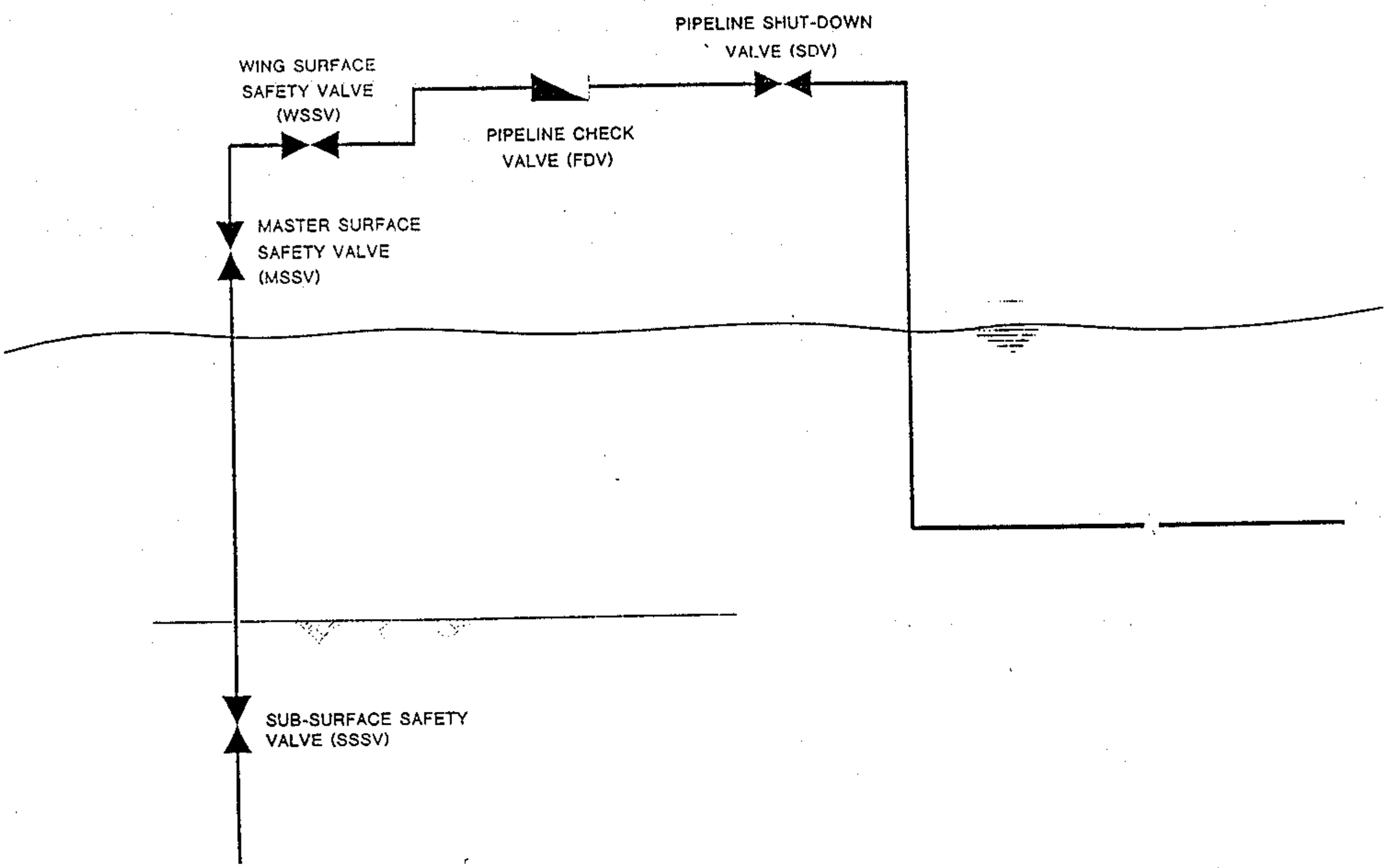

Figure 3 - Offshore Safety Systems Actuated for Hurricane Andrew

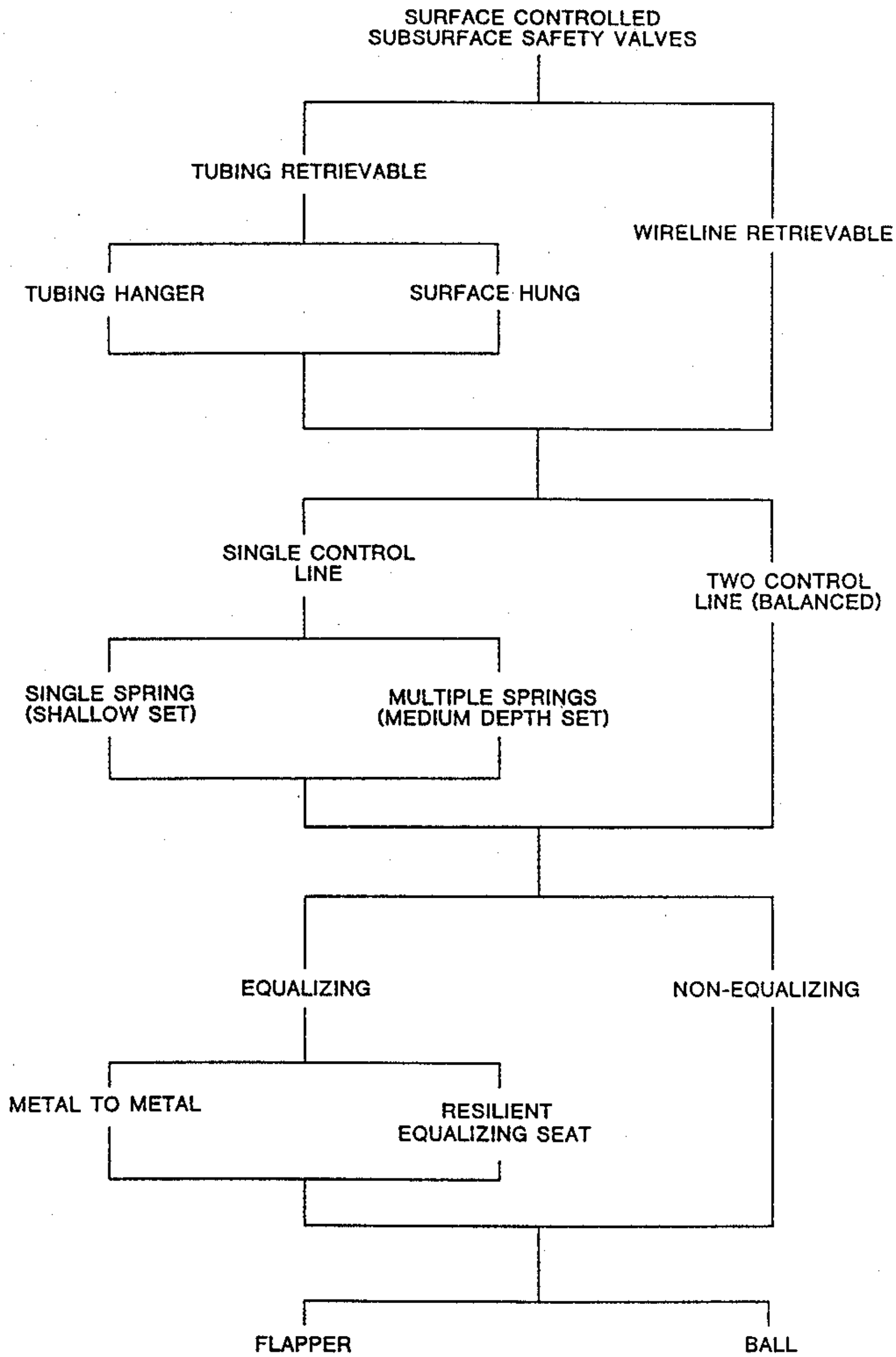

Figure 4 - Surface Controlled Subsurface Safety Valve Design Options

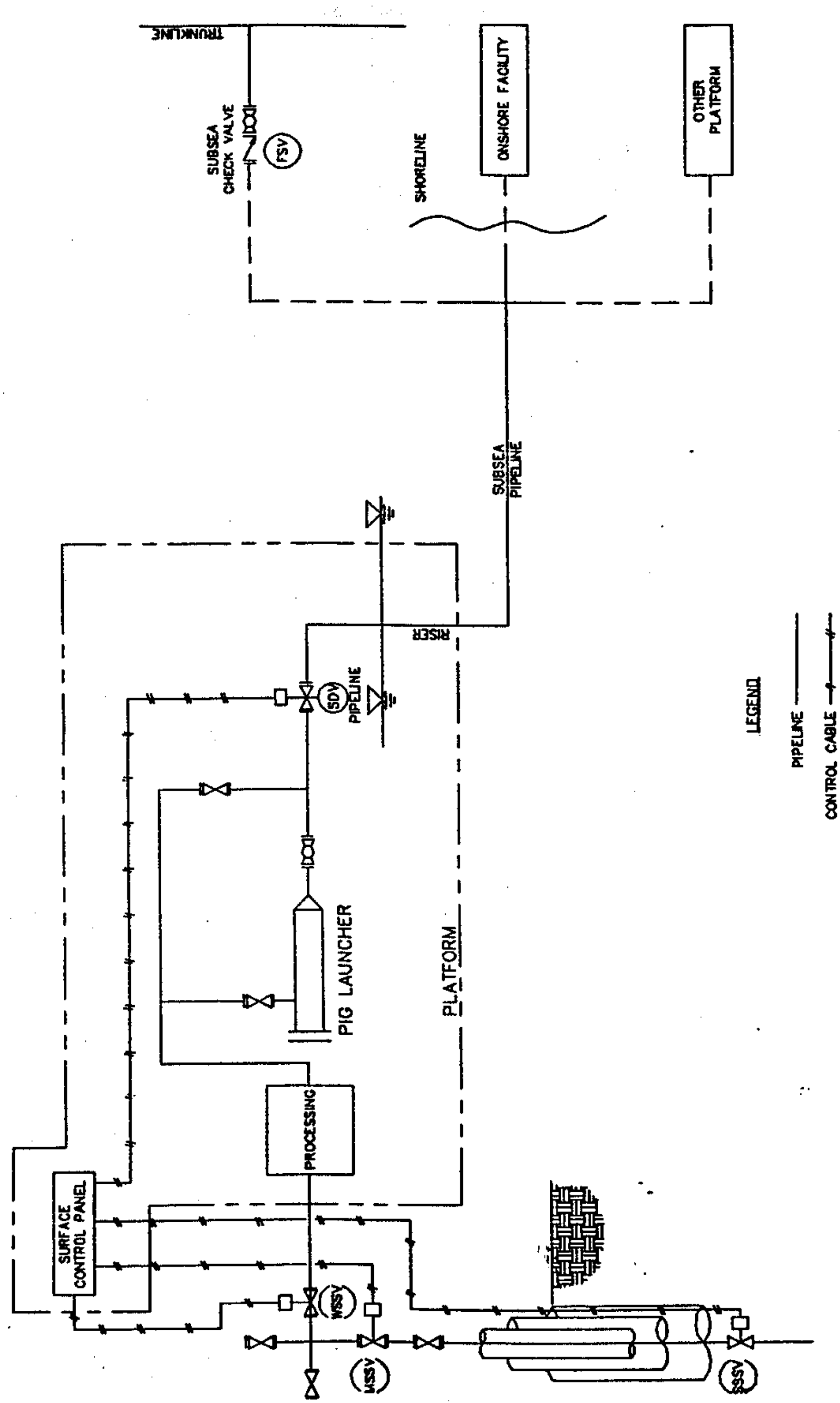

Figure 5 - Typical Geometry in Practice

KEYNOTE PRESENTATION V

"PIPELINE FAILURE DATA FOR HURRICANE ANDREW"

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Engineering Consultant
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Introduction

On August 25, 1992, Hurricane Andrew passed through the Gulf of Mexico, crossing an area with a large number of oil and gas producing fields in the Outer Continental Shelf (OCS). Hurricane Andrew was a category 4 level storm sustaining winds up to 140 miles per hour with gusts reaching 160 miles per hour and significant wave heights estimated to be at 35 - 40 feet. Typically, for a hurricane in the Gulf of Mexico, the highest wind speeds are experienced by facilities 45 - 50 miles to the right and 30 - 35 miles to the left of the path of the storm eye. Figure 1 shows the path of the eye of Hurricane Andrew tracked about 5 - 10 miles southwest of South Pelto block along with the corridor affected by the storm. Other blocks severely affected by the storm included South Timbaliar, Ewing Bank, Ship Shoal and Eugene Island.

Close to 2000 oil and gas producing facilities were exposed to severe storm winds. The damage to these facilities was quite severe and surpassed significantly the damage from any of the previous hurricanes in the Gulf. About 36 major platforms and 145 satellite well jackets and caissons were damaged. In addition, over 480 pipeline and flowline segments were damaged. Four jack-up rigs tilted off from their original position and six semi-submersible drilling rigs drifted from their location. In view of this enormous damage, the Minerals Management Service (MMS) initiated several studies to investigate various issues related to the storm's impact on the offshore production facilities. Operators of pipelines and platforms that existed in the shaded area of Figure 1 were asked to survey the relevant facilities. This paper includes partial results of the study that was sponsored by MMS to investigate the damage to offshore pipelines due to Hurricane Andrew.

Most of the pipelines and platforms installed in the GOM after the early 1970's were designed for the 100 year storm condition. Several of the structures installed earlier were designed on the basis of a 25 year storm criteria. While most of the older structures did not perform as well as those installed after 1970, several pipelines were damaged during Hurricane Andrew in spite of their 100 year storm design criteria.

Generally, hurricane induced damage to pipelines can be attributed to one or more of the following failure scenarios:

- Excessive pipeline movement on the seabed due to loss of on-bottom stability under the extreme hydrodynamic loading during the storm.

- Excessive pipeline movement due to impact from a mud slide.

- Damage to the platform riser or the riser-to-pipeline tie-in due to excessive movement of the pipeline on the seabed.

- Overstressing of the platform riser due to the platform movement during the storm.

- Damage from anchors and anchor lines of the unattended drilling and construction vessels that drift off-site during the storm.

The regulations require that all pipelines and flowlines installed in water depths of less than 200 feet be buried to a depth of three feet below the seabed. A pipeline buried to this level is expected to be protected from the hydrodynamic loading under the severe storm conditions. Most of the pipelines damaged during Hurricane Andrew were in water depths of less than 70 - 80 feet. The question naturally arises as to why such a large number of pipelines failed during Andrew. Although Andrew was a category 4 level storm, there have been storms of this and higher level that have crossed the Gulf in the past. Fortunately, during these past storms, the Gulf of Mexico was not highly developed and the resulting damage to offshore facilities was small.

A future storm of category 4 and above, which crosses a region of the Gulf that is densely populated with offshore production facilities, would have the potential to inflict a similar level of damage as Andrew. It is therefore important to identify the probable reasons for the excessive pipeline damage due to Hurricane Andrew so that the potential damage during future storms can be minimized. The results provided here give some answers that will be helpful to the industry.

Failure Data Analysis

MMS maintains a historical data base [1] on the pipeline failures that have occurred in the Gulf of Mexico since 1967. The recent data is available on computer whereas the older data is in hard copy. The computer data base is being continuously updated by MMS. As such, the results presented here are based on the status of the data base received during the study and do not reflect the subsequent updates and corrections to this data base made by MMS. All operators are required to report to MMS the pertinent information after a pipeline damage is noticed. The data base lists pipeline accidents by pipe size, operator, transported product, damage location, cause of failure and the repair action implemented or planned. Throughout this paper, unless explicitly specified, the term "pipeline" has been generically used to include both the transmission lines and the intra-field flowlines or service lines.

As described in [2], the principal causes of pipeline failures are: material failures, equipment failures, operational errors, corrosion or erosion, natural hazards such as storms and mud slides, and third party damages due to anchors, jack-up rigs, supply boats, trawling, etc.. Figure 2 shows a histogram for the annual pipeline failures in the Gulf during the ten year period of 1983 - 1992. In this figure, the failures due to all causes are compared with failures due to storms and mud slides. Prior to 1992, the only year with significant storm related damage to pipelines was 1985. During this year, about 55 failures resulted from four hurricanes (namely: Juan, Elena, Danny and Kate) that crossed the Gulf. Otherwise, prior to Hurricane Andrew, the pipeline failures due to storms and mud slides have been relatively small. A review of the MMS data base shows that during the period 1967 - 1991, there were only 97 storm and mud slide related pipeline failures. Comparing this with over 480 pipeline failures due to Hurricane Andrew shows the enormity of the damage inflicted by this hurricane.

The results presented here are based on an analysis of 485 reported pipeline failures in the MMS data base. The data was analyzed with respect to pipe size, pipeline product, water depth, cause of failure, location of failure, etc.. The results of the analysis are helpful to identify the significant failure trends.

Pipe Size

Figure 3 shows the total number of line segments in each pipe size (nominal diameter) damaged during Hurricane Andrew. This figure shows that the largest number of failures were among the 4" size lines. Williamson's study [3] has shown that within the corridor affected by Andrew, the largest number of pipeline segments were of the 4" size. However, the number of failures in this size exceeds the proportion of 4" size lines that have been estimated in the storm path. It is generally known that the storm affected area did include a large number of flowlines and small diameter pipelines.

For the sake of analysis, it is convenient to divide the pipe sizes into three groups, namely: small size (2" to 6" OD), medium size (8" to 16" OD) and large size (18" OD and above) [2]. By grouping the number of failures according to pipe size group as defined, it can be seen from Figure 4 that about 87% of the damaged line were from the small size group, 11% from the medium size and 2% from the large size group. This distribution is consistent with the results presented by Mandke on the previous storms [2]. Williamson's data [3] shows that within the corridor affected by Andrew, 80% of the line segments were of small size, 18% of the medium size and 2% of the large pipe size.

A total of about 766 miles of pipeline segments were affected by Andrew. They included 309 miles from the small size group, 205 miles from the medium size group and 252 miles from the large size group. It was not possible to determine the total length of the pipelines that existed in the corridor affected by Andrew.

Failure Cause

All reported failures were grouped according to the cause and the location of the damage. Table 1 gives a summary of the total number of pipeline failures that can be attributed to the identified primary causes. They include damage to or loss of the platforms or the wellhead jackets and caissons, mud slides impacting pipeline, third party damage from drifting vessels, loss of anodes and the protective cover, and damage to pipeline and riser from excessive movement of the pipeline or the platform during the storm. It should be noted that although in Table 1 each damaged pipeline has been assigned to a primary cause category, many of the pipelines could have been placed in more than one category. For example, the mud slide related failures could have been listed under the pipeline damage category. Pipelines attributed to damaged platforms could have been grouped under riser damage or pipeline damage, depending on the interpretation of damage report from the operator. About 253 pipeline segments were damaged because of the failure of the associated platform structure. This accounts for more than half of the total number of failures.

Table 1 - Distribution of Pipe Damage by Cause

Cause	Number of Failures
Mud Slide	10
Platform Damage	253
Riser Damage	103
Pipeline Damage	44
Third Party Damage	18
Loss of Anodes	28
Loss of Cover	9
Other	20

There were 10 failures due to mud slides. They were among pipe sizes of 6" to 18" in diameter with the majority in the so-called medium size group. Most of the mud slides resulted in separation of the break-away joint where used. Three cases resulted in damage to the associated riser and the pipeline section close to the platform. In five cases, only the break-away joint separated without damage to either the pipeline or the riser. Two incidents required replacement of 1000 and 2630 feet of pipeline segment, respectively.

About 103 cases of riser damage occurred which were attributed to either excessive platform movement, inadequate riser support clamps, or movement of the associated pipelines on the seabed. All of these incidents were limited to pipe of size less than 8" nominal diameter. This total also included cases where only the riser to pipeline tie-in was damaged, or where both the riser and the pipeline needed repair. For the 44 incidents of pipeline damage listed in Table 1, the primary cause was the excessive movement of the pipeline and they required only repair of the pipeline section. Again, as in the case of riser damage, the damage to pipeline section was mostly limited to pipe sizes less than 8" nominal diameter.

Third party damage to pipelines resulted in about 18 failures. As stated earlier, these were primarily due to the unattended drilling vessels that drifted from their anchored positions during the storm. Sixteen failures of the pipeline sections resulted from damage due to the anchors or the anchor chains of the drifting vessels. In two incidents, the jack-up rig close to a platform damaged the risers from direct impact. The majority of failures occurred on lines with sizes between 4" and 10" in diameter. One 20" oil line was damaged from the anchor of a drifting vessel which resulted in significant release of oil into the sea. Only a 60 foot section of this line had to be replaced for the repair. The rig that caused this damage was mothballed and anchored but broke loose during the storm and drifted.

About 28 small diameter lines with sizes 2" to 4" lost anodes. Eighteen of these incidents resulted in damage to associated risers. It seems that these lines, which were mostly installed for self burial, moved significantly towards the platform during the storm. It is interesting that none of the larger diameter (>6") lines experienced this type of failure.

The majority of pipelines that were damaged by Hurricane Andrew were in water depths less than 200 feet. For these lines, the regulation requires that all lines should have been buried to 3' below the seabed. There were 9 incidents where the lines were exposed or lost the cover after the storm. All of these cases were among the lines with sizes in the range 8" to 36" in diameter. These lines did not move out of the trench. None of these incidents resulted in damage to pipe wall and required only reburial of the line or replacement of the lost cover.

In addition, the failure data included one 12" size flare line that was damaged and 4 pipeline segments were modified to tie-in with replacement platform structures. For about 15 incidents, the failure cause was not identified.

In Figure 5, each type of failure has been grouped among the three pipe sizes (small, medium and large) by their percent contribution. Thus, for mud slides, the largest number of failures (80%) were among medium size (8"-16") lines. The failures associated with damaged platforms were highest among the small size lines (89%) followed by 9% from medium size and 2% from large size lines. About 95% of riser failures and 84% of pipeline failures were among small size line segments. For both of these types of failures, there were no failures from the large size pipe group. All failures with anode loss occurred among small size lines. Loss of pipeline cover was 56% among medium size lines and the remaining 44% among large size lines. Thus, each type of failure seems to have had a significant impact on lines of a particular pipe size.

Damage Location

The failure data was analyzed with respect to the location of the damage on the line. The data for all failures was grouped according to whether the damage occurred on the riser, the riser to pipeline tie-in, on both the riser and the adjacent pipeline section, or only on the pipeline. Thus, there were 94 incidents where the riser or the subsea tie-in were damaged. In 30 cases both the riser and the pipeline were damaged, and in 80 cases damage was limited to the pipeline section only. Figure 6 shows the results of grouping the data on damage location according to the pipe size. Among the small size pipelines, the largest number of failures occurred in the riser or the subsea tie-in. Among the medium size lines, the number of failures in the riser section and the pipeline section were almost equal. For the large size lines, all failures occurred in the pipeline section.

Failures Grouped by Product

The largest number of failures (218) occurred among lines transporting bulk oil. The failures among the service lines to satellite wells which are listed as lift and other service lines totaled 119. There were 76 failures among lines transporting bulk gas. Flare and multiphase flow lines accounted for 22 failures. Williamson's data [3] shows that there were 1084 oil line segments and 924 gas line segments in the corridor affected by Andrew. It seems that disproportionately higher number of oil lines failed compared to gas lines. The reason for this trend is not clear.

Figure 7 shows the failed pipelines grouped by the pipe size and the corresponding distribution of the transported product. Thus, for the small size lines and the medium size lines, the largest number of failures were among the oil lines. For the large size lines, the majority of failures were among gas lines. There was only one oil line failure in the large pipe size group. Most of the service line failures were in the small size line group.

Age of Damaged Lines

In the aftermath of Hurricane Andrew, it was initially suspected that the majority of lines that were damaged were perhaps very old and designed to a 25-year storm criteria. Also, with increasing age, the lines are expected to deteriorate in strength due to corrosion and erosion, and are thus more likely to fail. However, an analysis of the data shows that this supposition is not necessarily valid for storm related pipeline failures. The analysis excludes the pipeline failures associated with damaged platforms and other structures. The age of each failed pipeline was determined based on the recorded hydrotest date. Where the hydrotest date was not available, then the approval date for the line segment was used. The majority of the 136 failed pipelines had an age in the range of 6 to 15 years. There were only 13 lines that were more than 20 years old. For 29 lines in the data base, the age could not be determined.

Figure 8 shows the failed lines grouped according to age group and pipe size group. Total failures within each pipe size group are expressed as percent failures. Thus within the small size pipe group, 63% of the failed lines had an age of less than 10 years, 22% were in the range 11 to 20 years old, 4% were within 21 - 30 years old, 1% were within 31-40 years old, and for the remaining lines their age was not known. The age distribution for the failed medium size lines was: 26% less than 10 years old, 39% within the range 11 - 20 years of age, 7% were 21 - 30 years old, 3% within the range 31 - 40 years old, and 25% with unknown age. For the large size lines, 83% were within 11 - 20 years old, and 17% were 21 - 30 years old. If the pipeline age was a significant factor, then the percentage of lines failed would have been proportionately larger for the increasing age group. However, the data shows that there is no clear correlation between the age of the line and its failure frequency due to the storm.

Pollution From Damaged Lines

Within the MMS data base, there was only one incident with an oil spill resulting from pipeline damage. This was a 20" size oil line which was damaged by an anchor from a drifting drilling rig. The line released about 2000 bbl of oil in to the sea. MMS reports state that there were 10 other incidents with small quantities of oil released. The total oil spill from these ten failures was estimated to be 500 bbl. Thus excluding one major incident, the oil spill pollution from damaged pipelines during Hurricane Andrew was relatively insignificant.

Conclusions

1. The majority of damaged pipelines were of small size (2"-6" OD) and in water depths of less than 70 feet.

2. Among the small size lines, the damage mostly occurred in the riser section.

3. The majority of failed pipelines transported oil, or were flowlines to satellite wells.

4. There was only one major incident of oil spillage, with a release of about 2000 bbls.

5. A large number of small size lines were installed for self-burial. This may have contributed to their failure.

6. Pipe age does not appear to be a significant factor contributing to storm related failures.

7. A very large population of pipelines and flowlines existed in the corridor affected by Andrew. This may have contributed to the large number of failures during the storm.

Recommendations

1. Improve safety level in platforms and associated structures to minimize damage to associated risers and pipeline tie-ins.

2. Improve the anchoring and station keeping capability of mobile rigs that will be left unattended during the storm.

3. Industry needs to develop improved design methods for protection of small size lines in shallow water depths and in underconsolidated soils.

4. Platform risers and their support clamps should be carefully designed and analyzed to ensure their safety under 100-year storm conditions.

5. Periodic inspection and maintenance of risers and supporting clamps should be implemented to ensure their survival during severe storms.

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2. Mandke, J. S., "Corrosion Causes Most Pipeline Failures in Gulf of Mexico", Oil & Gas Journal, October 29, 1990.

3. Williamson, W., "Overview of OCS Pipeline Damage Occurring During Hurricane Andrew", International Workshop on Damage to Underwater Pipelines, New Orleans, February 1995.

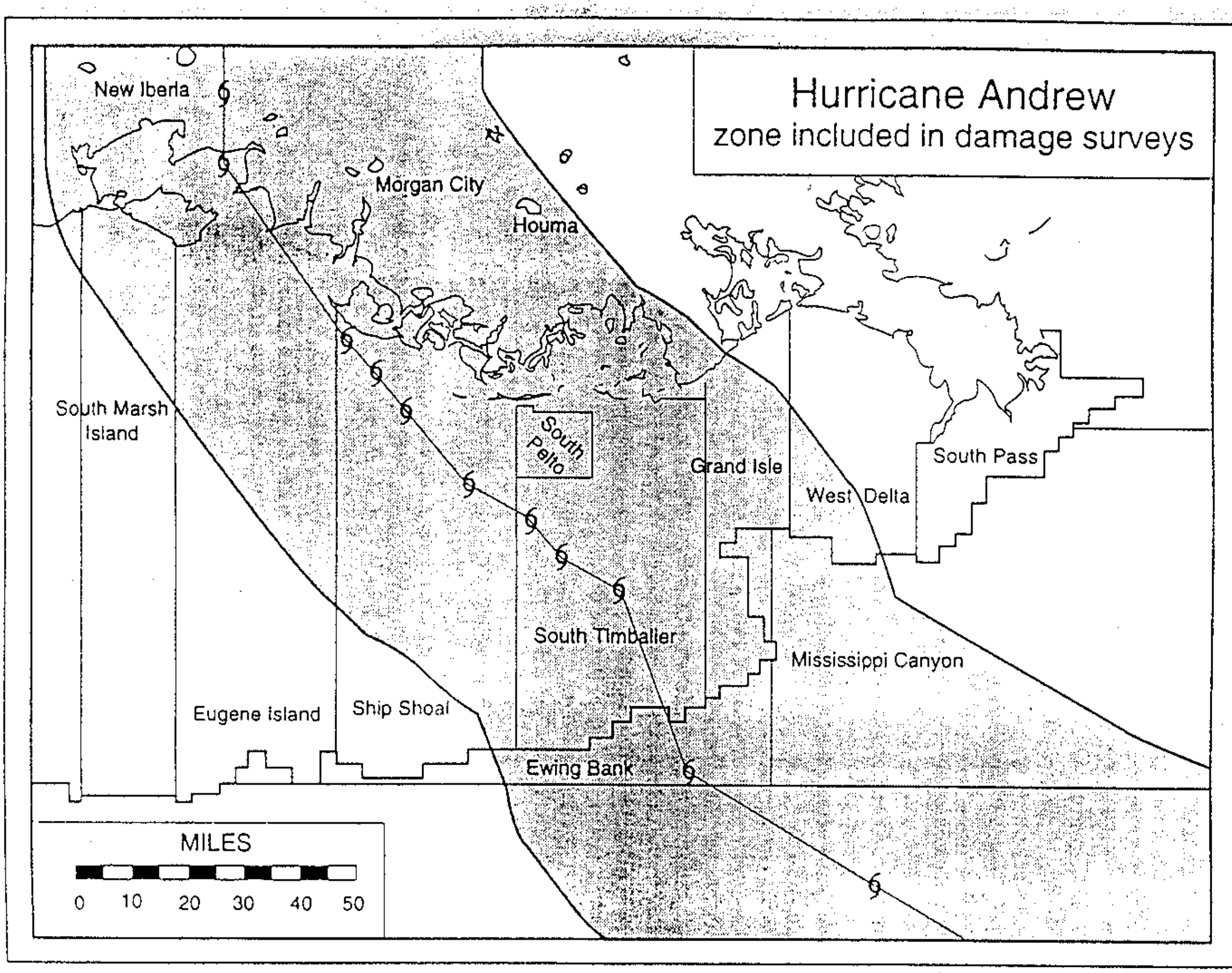


Figure 1. Path of Hurricane Andrew

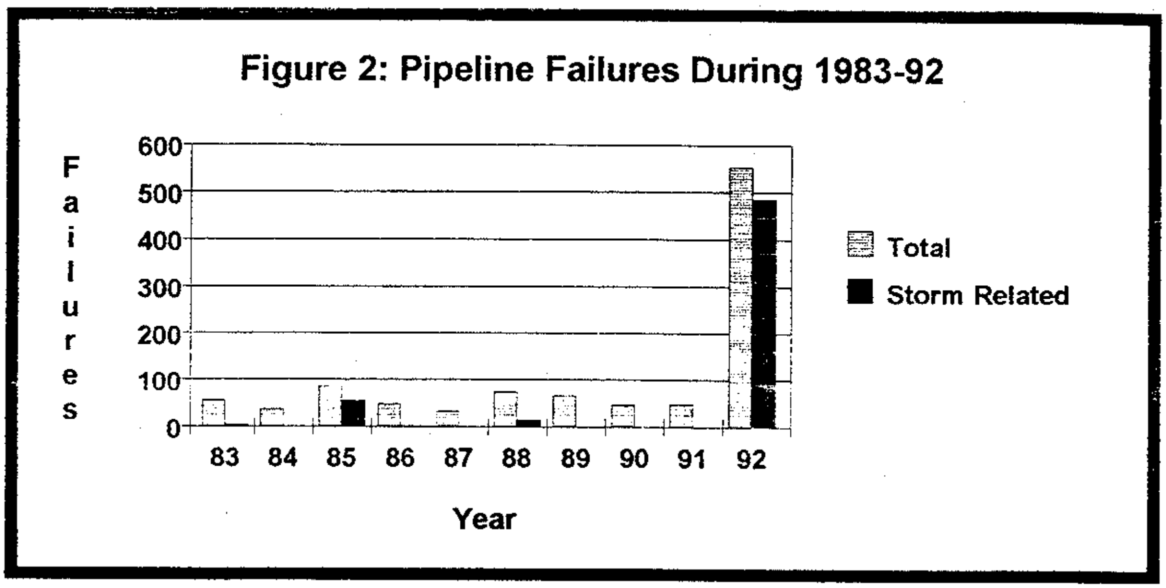


Figure 3: No. of Failures per Pipe Size

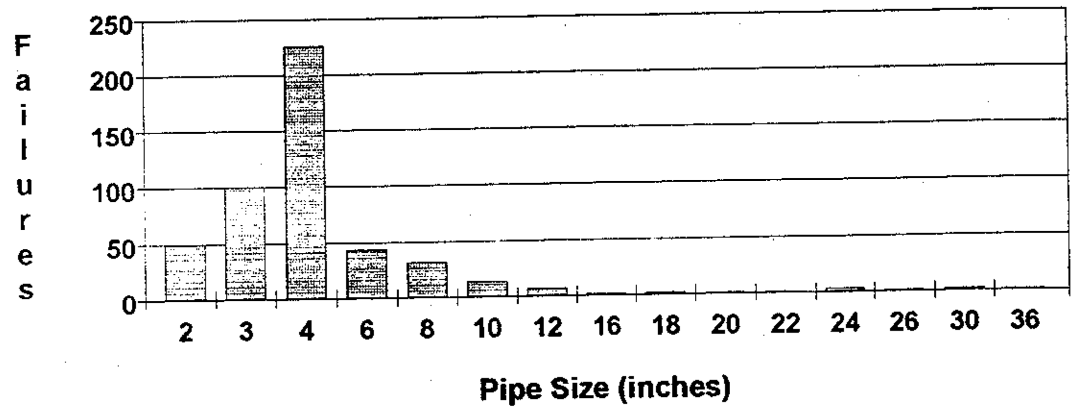
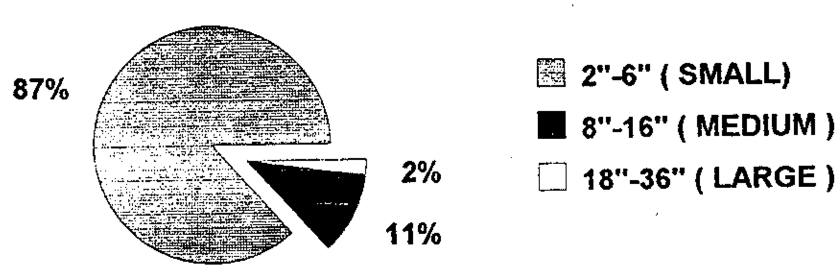


Figure 4: Failures per Pipe Size Group



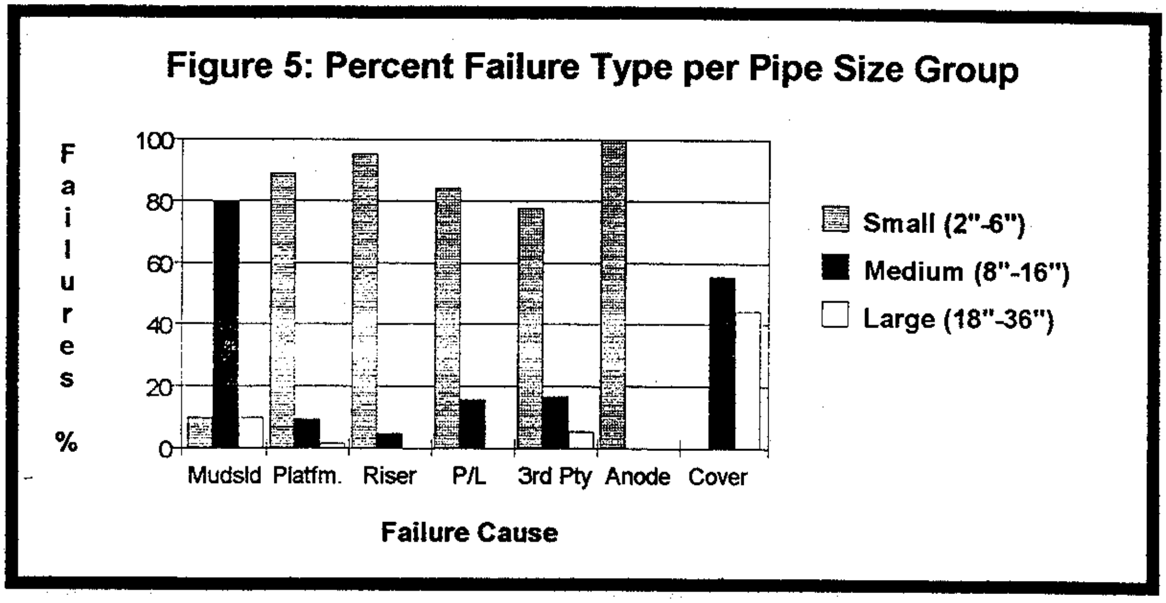


Figure 5: Percent Failure Type per Pipe Size Group
F a i l u r e s %
100
80
60
40
20
0
Mudsld
Platfm.
Riser
P/L
3rd Pty
Anode
Cover
Failure Cause
Small (2"-6")
Medium (8"-16")
Large (18"-36")

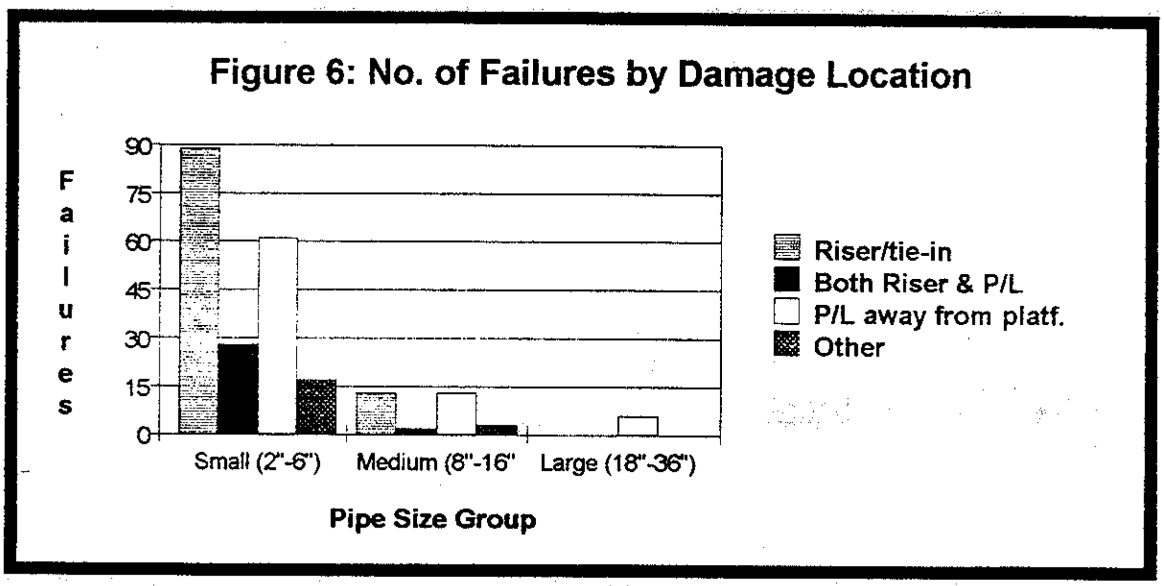


Figure 6: No. of Failures by Damage Location
F a i l u r e s
90
75
60
45
30
15
0
Small (2"-6")
Medium (8"-16"
Large (18"-36")
Pipe Size Group
Riser/tie-in
Both Riser & P/L
P/L away from platf.
Other

Figure 7: No. of Damaged Pipelines by Product

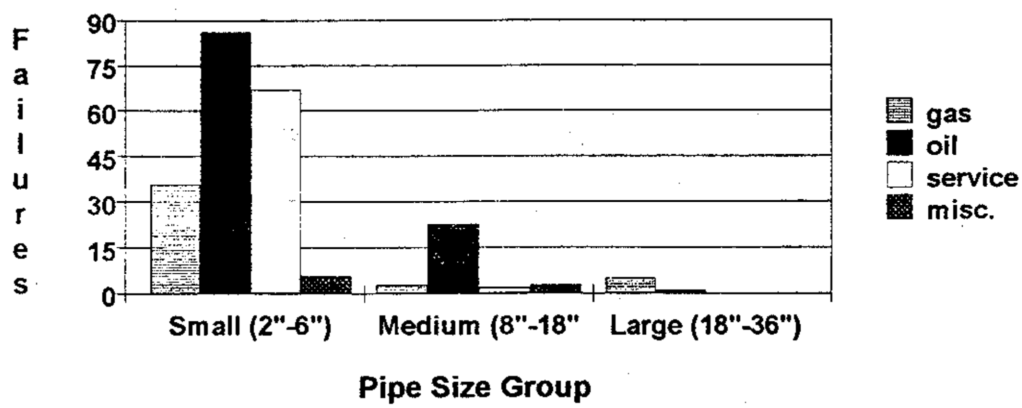
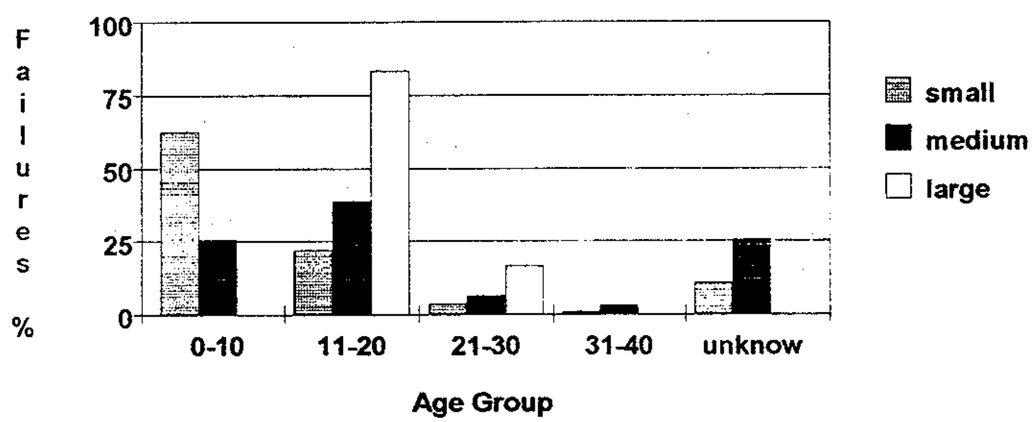


Figure 8: Percent Failures by Age Group (w/o platform damage)



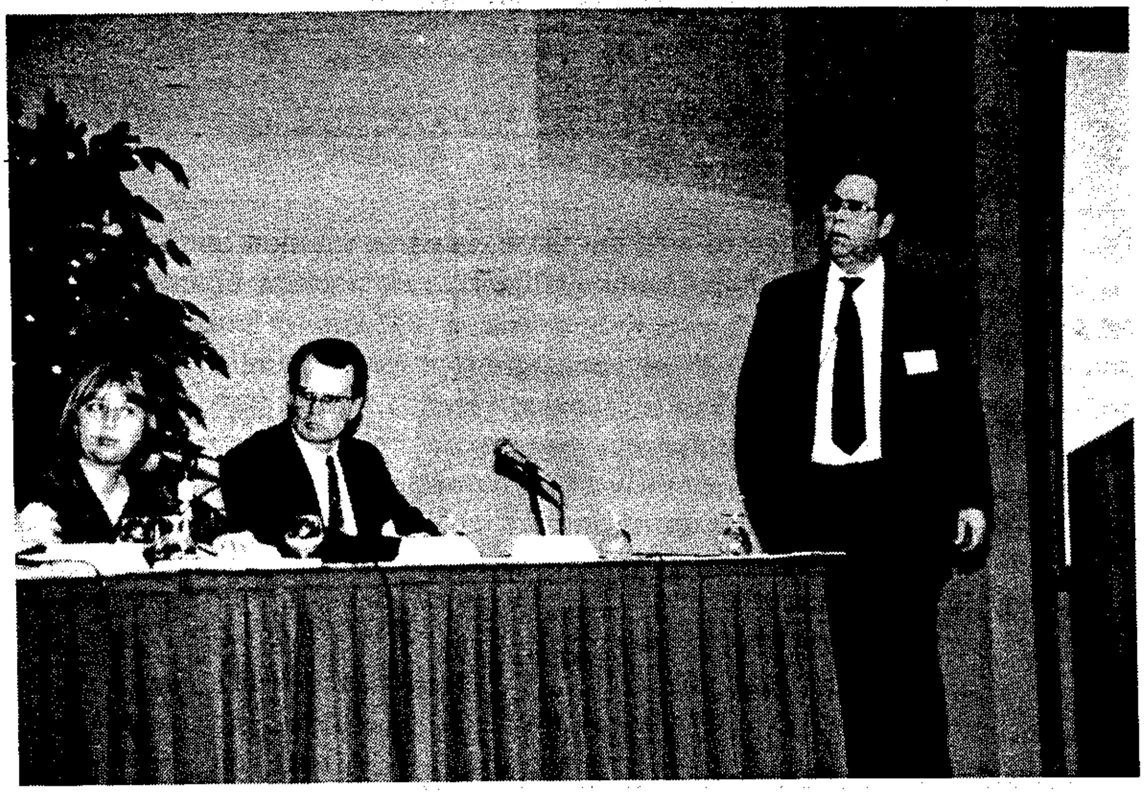
SPECIAL WORKSHOP ON "PARTNERING"

"ANATOMY OF RISK MANAGEMENT PROCESS"

Discussion Leader:
Charles Webster
Crisis Management Consultant

The Discussion Leader Briefing the Panel

Debate Underway in Part 1 - The Partnering



Panel Discussion for Part 2 - The Crisis

Summing Up after Part 3 - The Aftermath

PART 1 - THE PARTNERING

Welcome to part one of a multi-phase panel facilitation intended to surface and discuss best practice as it applies to qualitative risk assessment, emergency response and pro-active partnering with oversight agencies. This will be a scenario-based exercise commencing with panel debate concerning proposed purchase, by Colossus Energy Company, of an existing Gulf of Mexico pipeline. If we are successful, you will leave today with useful ideas and approaches you can consider for immediate implementation, on the job. To be successful, we will need your input as we proceed. So look at this as a two-way communications exercise and write down questions or issues you want to discuss. We will stop our discussions at several points during each phase of the program and ask for audience input.

As preparation for what is to follow, I want to suggest that implementation of ideas discussed here today would likely require some level of paradigm shift by both industry and the oversight community. A what shift you say. A short story might help. Back in the 1970's, a Swiss watchmaker invented the LED display watch. It had no moving parts and was displayed at the world's fair. The Swiss knew it wasn't really a watch in that it had no moving parts. They didn't even patent the device. At the world's fair, Japanese entrepreneurs were fascinated with the watch, moving parts or not. Within ten years, 90 percent of all watches produced in the world had no moving parts and were produced in Japan. Arguably, the Swiss watch making industry has never recovered from the paradigm shift in thinking about what must move in order to track time.

The historic relationship between regulators and the regulated has been based on compliance oversight. The question today is whether we have reached a point where we can partner and shift to a risk assessment based process which better protects society and the environment.

As a Crisis Management Consultant to the energy industry, I suggest to companies a simple process to be employed when crisis strikes. In the absence of crisis, I suspect past history can also be illustrated by a few slides. We will reconsider the question in a few hours.

Each of you has received background material on the scenario and the fictitious companies involved. Before we begin, you should know that the panelist participating here have not been provided with any additional information. They are here as experts in their fields and will be dealing with issues as they arise. I suspect this approach will produce more interesting and insightful results, though a formal risk assessment by our panelists might have had them conclude that participation was foolish. Suffice it to say that we aren't sure where we will end our discussions, but are likely to touch on many issues of current importance to you in the natural gas industry.

To help us out today, I am pleased to introduce our initial panelists. They are:
Sal Ballassi, who will serve as Chief financial officer for Colossus. Sal is a retired executive with Transco.
Chris Whitney will serve as the civil engineer for Colossus. Chris is a Tenneco engineering supervisor.
Bob Winters will look at corrosion issues in play. Bob is a consultant to Tenneco on corrosion matters.
Looking at regulatory considerations for Colossus in this phase will be Kathleen O'Leary. Kathleen normally works for Columbia Gulf.

Let's begin...

The date is January 3, 1990. You, as senior managers for Colossus Energy Company know that exploratory drilling in the Gulf of Mexico has discovered a massive sweet gas reserve (Slide #1). The reserve is indicated on this chart of Gulf of Mexico waters southwest of Grand Isle, Louisiana. Colossus has successfully maintained information security on the dimension of the find and is moving quickly to determine whether new pipeline construction will be required or whether the company should seek to purchase an existing transmission system. Colossus exploration experts predict the new field will produce 600 MMCFD of sweet gas, when fully developed.

Considering time required for permitting, environmental assessment, drilling and development of transmission links, Colossus hopes to begin producing gas in 1994. Existing facilities are being evaluated for initial deliveries of 250 MMCFD in 1995. Additional tie-ins to the UNE System are contemplated as field production increases. Slide #1 also shows a pipeline system owned by NatGaz International, Inc., which is being evaluated by Colossus. The Pipe Line was constructed in 1980 and has operated with few significant problems for about ten years. Due to declining production from existing tie-ins, the pipeline system has a current throughput of just over 295 MMCFD and is capable of carrying a great deal of additional gas.

Colossus analysts know that NatGaz carries considerable debt and is trying to expand international operations while reducing its U.S. presence. In fact, NatGaz has stated publicly that the environmental and regulatory situation within the United States is anti-development and responsible for exporting energy dollars to other parts of the globe. When the Dow Jones News Service reported that NatGaz Chairman David Heath told security analysts that the Pipe Line was no longer a core asset, you were tasked to explore the possibility of purchasing the line.

Upon making contact with NatGaz, you are provided with data outlined in handout #1. You know that the Pipe Line was built to transport sweet natural gas. You find information indicating that the 16-inch lateral line extending southeast from the 24-inch feeder line has experienced four minor leaks during the past three years. These were identified as internal corrosion related to carbonic acid produced from CO_2 and water interaction. All four leaks were successfully fixed with installation of subsea clamps. No leaks have been reported on the 24-inch or 30-inch sections of the line. You are also aware that active production on the central gathering platform has resulted in past introduction of sand and large amounts of water into the 30-inch main line to shore. Within two weeks of the incident, the 30-inch was cleaned and dewatered. The pipeline system operates at 1200 psi.

During initial discussions, NatGaz makes clear its intent to sell the Pipe Line rather than negotiate a throughput agreement.

to Sal: Colossus Energy is known in the industry and regulatory community as a first class operator. You view compliance as a floor rather than a ceiling. At the same time, Colossus is successful in large part because of its ability to control costs and properly assess risk. Based on what you know so far, is the NatGaz pipe line a potentially good fit for Colossus? When you look at a possible acquisition, what kind of assessment team do you put together and how do their skills mesh in the discovery and evaluation process? If you had your druthers, would you build a new pipeline system instead of purchasing a ten year old system? Everything being equal, why buy when you could build?

to Chris: What are the factors used to evaluate the original design and construction of this system? What kind of problems will you face if Colossus purchases the pipe line and tells you to tap into the existing system? Information provided by NatGaz verify that 1104 standards and inspection quality were maintained through all phases of original construction. Is that information complete enough, or will there be additional original construction data that you will want to request as part of the acquisition assessment process. How would you describe the quality of construction quality oversight back in 1980? Does the fact that four corrosion leaks have occurred on the 16-inch lateral over the past three years suggest original construction negligence?

to Sal: Do you believe that past problems with something like a pipeline system are necessarily a predictor of future financial exposure for a company like Colossus?

to Chris: When you look at maintenance records for a pipeline, what kind of data jumps out at you? Based on your experience, does the quality of record keeping indicate the quality of maintenance performed? Does it look like NatGaz has been reactive, pro-active or somewhere in-between in maintaining this line? Is there any relationship between original construction cost and annual maintenance budgeting as a gauge of maintenance quality?

to Bob: So far, it looks like this might be a good transmission fit for the future of Colossus. From a corrosion standpoint, how good or bad might this system be? What does your expertise tell you about past experience as a predictor of future operational performance? What are some of the tools available to prevent internal corrosion? Based on the performance results on the 16-inch pipeline, do you think problems exist on the 24- and 30-inch lines? Are you going to recommend that smart pig inspection be conducted as part of due diligence, in advance of a purchase offer? Will you limit the smart pig to the 16-inch lateral or recommend that smart pigging be conducted in all three segments of the system? How would you rate the NatGaz maintenance staff in making a purchase recommendation to Colossus management? Tell us what factors would enter into your rating? What more do you want to know about NatGaz maintenance procedures before you make a recommendation? What impact does gas quality have on this situation? What data do you need in order to properly predict the future integrity of this system?

to Kathleen: What is your focus as a member of this assessment team? How important is the previous record and reputation of NatGaz in determining how regulators will view this potential acquisition. I assume from a regulatory standpoint that linking with an existing transmission system to shore will be easier than securing permits for a brand new system? How much does that weigh into your consideration of this potential acquisition target?

to Chris: What kind of smart pig program would you recommend based on presented information? What are the cost estimates associated with pigging each line? What are the difficulties associated with each? How does the availability of capital dollars affect your recommendation? What will you look for in smart pig data as it relates to pipe line welds and running wall thicknesses? How accurate is the data derived from today's smart pigs? How would you repair or remove defects detected by pigging operations?

to Kathleen: What additional input will you seek from this team before making a recommendation? Would Colossus discuss this purchase with MMS, DOT, TRC or others prior to purchase? How can non-Colossus resources add value to your decision making process?

to Sal: As a team leader, you have heard a lot of input from your team. You know that NatGaz is willing to do a very attractive cash deal if things can be wrapped up quickly. I'm curious as to how this data will be combined into a formal recommendation to senior management of Colossus, and how the availability of capital dollars for pigging operations will affect your recommendation, but first, I'd like to pause and ask the audience what issues you would like to raise or clarify. .

10 Minute audience Q&A

Thanks for the input.

to Sal: Your regulatory specialist said Colossus would discuss this potential acquisition with oversight agencies and others as part of the risk assessment process. Let's bring in some additional panelists and see what they have to offer.

First, let me introduce Bill Gute, Director, Eastern Region for DOT.
Next, from MMS, please welcome Ernie Danenberger.
Finally, from the Texas Railroad Commission, Mary McDaniels.

Welcome to our acquisition deliberations. I assume it is not customary to be asked for advice on a potential acquisition, but I also suspect you believe there are advantages to being included in the risk assessment process. Let's turn to DOT.

to Bill: Colossus wants to do the right thing. Based on what you have heard so far, what additional issues might they benefit by pursuing and how can your office help? Do you see any conflict of interest in talking with Colossus about this purchase? Would DOT support the concept of pre-purchase partnering as a voluntary program for all gas transporters?

to Ernie: Sal and his team have developed what they think is a pretty clear picture of the system. You have been invited in to discuss the possible acquisition. Tell the team where your organization can add value to the deliberative process? Do you have failure history data they might not have that could indicate whether or not to proceed with this deal? Can they discuss issues like right of way permits for proposed tie-ins prior to purchasing this system? Will you discuss issues like tie-in design before they make the purchase decision? Is there conflict of interest or any other legal problem in sharing such data?

to Sal: Your reaction to what MMS has to offer?

to Colossus Panel: Any other comments from Colossus management on MMS input?

to Ernie: How well are your people trained to participate in a collaborative risk assessment process?

to Mary: From your perspective as a state regulator, would you like to be invited in as part of this purchase assessment process? Where can your people add value in ways different from MMS and DOT?

to Regulators: Somewhere in here there is the matter of trust. I suspect at least a few people in the audience may be wondering whether this is ramping up as a model for further government intrusion into private enterprise. How do you react? But in working together, might you be gathering knowledge that could be used later to prosecute companies like Colossus?

to Sal: Your reactions? Okay, it's time to make your recommendation. You don't have enough capital available to pig all of the UNE system lines. But it looks like a pretty good deal. Do we proceed with purchase or not? And before you share you decision, know that failure to buy the UNE system will put a black rhino bullet through the rest of this program.

Great decision. At this point, let's go back to the audience and find out what issues have been raised by state and federal participation in the purchase assessment process. Don't be shy. We are bending if not breaking the historic paradigm and want to hear your ideas and concerns.

10 minute Q&A.

Thanks for your input. Let's take a 15 minute break and then move the clock forward to the present. I smell a crisis in the offing. Thanks for your attention so far.

Part 2 - THE CRISIS

Welcome back. It is now Saturday, February 18, 1995. Colossus has long since purchased the System and has completed tie-in as indicated on this slide (Slide #2). New field production, combined with existing production has resulted in a current throughput of 556 MMCFD of sweet gas at a flowing pressure of 1,200 psi. (Slide #3). Since the purchase of the UNE System, smart pigging has been conducted on the 16" and 24" segments of the system, with pigging of the main line scheduled for the second quarter of 1995. Pigging data resulted in the replacement of 1,000 feet of pipe on the 16-inch line in the area of previous repairs. The pigging of the 24-inch pipeline revealed no indications of internal corrosion. In that section, the liquid pigging and inhibitor program was deemed adequate. There have been no major system failures or releases since the purchase back in 1990.

At 07:15 hours, Colossus system operators in Houston note a sharp drop in line pressure at the central gathering platform and start the process of shutting in production wells (Slide #4). Attempts to communicate with five Colossus production personnel on the central gathering platform are unsuccessful. Colossus makes contact by radio with a Marathon Oil Company platform approximately 1.75 miles northwest of the central gathering platform and is told that a major gas release and explosion have occurred (Slide #5). They estimate that flames are rising more than 300 feet in the air and offer any assistance possible.

As you will notice, we have made some panel changes up here. Let me take a moment to introduce new additions.

First up is Megan Mastal, a Tenneco public affairs specialist who will serve as a CNN reporter in New Orleans.
Responding on behalf of DOT will be Bill Burgess, senior staff engineer with the Southwest region pipeline safety.
From MMS, we have Alex Alvarado as the MMS pipeline supervisor.
The Coast Guard would also be involved in this incident and we appreciate the participation of Lt. Cdr. Ken Parris.

Thank you all for joining us.

to Chris: What are your first actions from a notification and operational response standpoint? What are your primary concerns? What is the potential of this situation?

to Bill: How are you going to ramp up your response? How will you link with the Colossus team?

to Alex: Same questions?

to Cdr. Parris: What is your role in this incident?

to Mary: The central gathering platform straddles the line between state and federal waters. What are your interests and what role do you play in this response?

to Cdr. Parris. You get word that a mayday was received from a private pleasure craft which was reportedly tied up at the gathering platform on Friday night. Information is that a fishing vessel participating in the Labor Rodeo fishing tournament was in flames. The name of the vessel, the "Cajun Spice", indicates ownership by famed chef Paul Prudhomme. How does that affect your response strategy?

to Megan: You get word of the explosion and rumors about possible celebrity casualties. What is the potential of this story? Look around the panel and tell me what color hats the various participants are wearing from a media perspective? Who do you want to talk to? Is Colossus presumed innocent until proven guilty?

to Chris: What physical response has your company initiated? What most likely went wrong out there? Can you shut in the gas flow? How many people on the platform are at risk? What kind of mutual aid arrangements do you have with other operators in the area? How long will it take Colossus to get a visual on the situation?

to Agency Panel: Can any of your organizations get there quicker to help Colossus assess the situation?

Let's move forward in time. It is now 08:45. Marathon Oil officials report they have recovered one person from the water adjacent to the central gathering platform. He is seriously burned and enroute to a shoreside burn unit. The worker said it appeared that a major failure occurred underwater at the base of the 30-inch riser. He said gas boiled to the water's surface and may have been ignited when a pleasure boast started engines to escape the area. The worker says chef Paul Prudhomme, former Louisiana governor Buddy Roemer and four other passengers were on the boat, along with a crew of three. The worker does not know what happened to them. Marathon reports that the boat was engulfed in the fireball and that no survivors have been seen in the water.

to Sal: As CFO of Collossus, how are you responding to the disaster? Does Colossus accept liability for this tragedy? Does your liability extend to the people and the boat? Could this incident bankrupt your company? Megan is on the phone from CNN. Will you talk with her? Okay, you guys chat and we will listen in. Megan, you have Sal for three minutes.

to Agencies: We have been talking about partnering all day. Does the potential death of celebrities make it more politically difficult to partner with Colossus now?

to Alex: As the response unfolds, where will you add value and what role will you play in trying to assess Colossus performance? Aren't you both a partner and prosecutor? What demands are being placed on you from Washington?

to Cdr. Parris and Bill: Same issues?

to Agencies: When will your formal investigations commence? What will you be looking at in trying to determine what went wrong? Since Colossus worked with you before purchasing the system and has invited you to think through risk assessment issues with you in the past, will that influence your thinking as you look into this disaster?

I'd like to re-open this to the audience, but first, let's go around the panel starting with Sal, and get your views on how Colossus and the agencies represented here can reduce the impact of this disaster. From a public perception standpoint, Colossus is likely to have little or no credibility right now. Agencies on the other hand are more likely to be trusted by the public. How far are you agencies willing to go publicly to say that Colossus is a good outfit that experienced an unfortunate incident? Will you get in trouble with your bosses if you seem to be publicly defending the folks who may have killed a world famous chef and a former state Governor?

Panel input...

to Megan: Is this a national or international media story?

to Agencies: How will media scrutiny affect your positions as oversight agencies?

to Sal: How do you feel now about this partnering idea?

to Megan: What can Colossus and the agencies do with the media to get through this disaster with the least amount of injury to their assets or image?

to the audience: What is your reaction to what you are hearing? Do these agency people have credibility or are you convinced they will turn on you if the chips are in the fire? Let's hear your questions.

Audience Q&A

Thanks for the input. How about a ten minute break and we will move to the post incident environment.

PART 3 - THE AFTERMATH

Welcome back again. The date is now March 30, 1995. You have the metallurgical analysis of the 30-inch riser indicating the cause of the failure. The analysis tells us that erosion/corrosion which occurred during the earlier production upset was the most likely cause of the riser failure. A great deal of relationship and political stress was created when a major system failure critically burned one worker and killed four people on the central gathering platform and all nine passengers on a pleasure boat including former Governor Roemer and Chef Prudhomme. Congressional hearings have been held excoriating the management of Colossus for the way they do business and the solvency of the Colossus is still in some doubt due to destruction of the platform, deferral of gas production, lawsuits and pending regulatory findings.

to Sal and the agencies: If partnering and collaborative risk assessment are indeed a better way to do business and protect societal interests, how do we get past the tragedy and work together to prepare for future operations? Are there things we might have done to avoid the tragedy which occurred? Are you saying that risks can be managed, but not eliminated?

to Bill, Ernie and Mary: I am led to understand that currently, there is little coordination even within some oversight agencies as to how companies like Colossus are urged to spend their dollars. That in fact, DOT in one region of the country may not evaluate the needs of one system in comparison with the needs of systems in other geographic regions. Using a declared hazardous facility order, could the system now in place have forced Colossus to spend capital dollars on other projects instead of thoroughly evaluating all aspects of this system before the line failure? By this, I mean, is there a global approach we should be pursuing in place of the current system which has regional oversight agencies pushing agendas without knowing the consequences on a company's total operations?

Back to the situation with the System, I'd like to go around the panel again and ask each representative to tell us how they can add value to the post-incident risk assessment and recovery process. Sal, I'd like you to listen to the input from your agency colleagues and then comment at the end.

My thanks to the panel for exposing themselves to some tough interrogation. Please remain here so that we can give the audience a final chance to chat with you. A few closing thoughts before we go to Q&A. When I was approached on this project, I found the concept of partnering intriguing. Perhaps not surprisingly, many industry folks I spoke with, thought the idea was daffy and unworkable. Frankly, that's how many people in the oil spill response business felt about industry/agency collaboration five years ago. But with the passage of time we have learned that industry does not have all the best ideas on how to prevent incidents. And we don't have a lock on the best process for dealing with spills when they occur. We have discovered that oversight agencies can be part of the solution. And so, let's go back to the barnyard and consider the possibilities.

(Second pig slide). Maybe this is what smart pigs ..and cows.. will look like in the future. Presenting yourself to society as a team that cares is likely to result in less outrage and a lower total project cost. Take these ideas home and see if they can be applied to your operations whether industry or agency. In closing, I'd like to open the floor again to the audience. What questions do you have, realizing that your queries are the only thing between this panel and the hospitality bar?

Closing. Thanks again to our panelists. We appreciate your willingness to come up here and deal with some tough issues. Best of luck as you proceed with the workshop.

WORKING GROUP REPORT 1

"REGULATORY ISSUES"

Gary Zimmerman, Shell Oil Co.
Mark Berman, AMOCO Corp.

Introduction

The group started with a review of the schedule, objectives, and format of the session, and a general outline of the issues.

The Federal and State Rule-Making Process was discussed, and a presentation made in this respect by Carl Anderson of the Minerals Management Service. The application of risk management techniques was considered and the relative advantages and disadvantages debated. There was a general consensus as to the importance of cost-benefit considerations, and the role of proper evaluation of comments both from industry and field regulatory personnel.

Agency Jurisdiction and Enforcement was another issue that was debated, including the Memorandum of Understanding between the Minerals Management Service and the Office of Pipeline Safety. The relative relationships between the OPS and the state agencies, and between the MMS and the state agencies, was the subject of some discussion, and a number of participants felt that this could be simplified.

Cesar DeLeon of the Office of Pipeline Safety, Department of Transportation, led some discussion on this point, in particular on the proposed revision of the Memorandum of Understanding (MOU). A draft has been published this year and is contained in Department of the Interior, Minerals Management Service 30 CFR Part 250 Subpart J, and Department of Transportation, Research and Special Programs Administration, 49 CFR Parts 191-195 (Offshore Pipelines). This outlines how the DOI and the DOT are proposing to revise their MOU, originally dated May 6, 1976, concerning their respective responsibilities concerning offshore pipelines. This action will redefine the boundary lines over which MMS and RSPA exercise their inspection and enforcement roles, giving MMS greater inspection responsibilities over offshore pipelines previously inspected by RSPA. This is intended to result in more efficient utilization of government resources for offshore pipeline inspection.

A considerable amount of discussion took place on this subject, since there are about 16,500 miles of active outer Continental Shelf (OCS) oil and gas pipelines jointly regulated by DOI and DOT. Under the existing MOU, DOI has primary responsibility for about 4,800 miles of these pipelines delegated to the Minerals Management Service (MMS). DOT has primary responsibility for the other 11,700 miles of those pipelines delegated to the Research and Special Programs Administration (RSPA). The primary concerns with operating pipelines offshore include protecting life and property offshore, and protecting the OCS from environmental damage resulting from pipeline spills. These issues are of paramount importance to both MMS and RSPA.

As documented by the National Academy of Sciences, while offshore oil and gas production operations contribute less than 2 percent by volume of the oil that is spilled into the sea, pipe lines accounted for over 97 percent by volume of the oil spilled from OCS operations. These spills resulted almost entirely from anchors, construction operations, or fishing trawls that struck the pipelines and caused them to rupture. Corrosion related pipeline spills tend to be minor compared to spills resulting from external damage - however, because the pipeline system is extensive and aging, MMS and RSPA are also concerned about oil spills resulting from corrosion.

The adequacy of existing regulations was addressed, including SDV's, depth-of-cover inspection, the role of smart pigging, leak detection, riser inspection, and pending regulations in these respects. Some discussion took place on these topics, led by Gary Zimmerman of Shell Oil Company. It was pointed out that there was a separate MOU on Oil Spill Response, pursuant to the Oil Pollution Act. Under this separate MOU between DOI, DOT, and the U.S. Environmental Protection Agency, the agencies have divided their respective responsibilities for oil spill prevention and response according to the definition of "coast line" contained in the Submerged Lands Act, 43 U.S.C. 1301(c) - see 59 FR 9494; February 28, 1994.

Although some participants expressed a certain amount of dismay at what some people saw as an increasingly onerous regulatory environment (particularily those operators liable to become subject to a change in regulatory responsibilities), the point was made that the MMS has regulatory procedures under which departures from its requirements may be granted on a case-by-case basis, provided there is sound engineering analysis that shows the operation, practice, or situation will provide an equal or greater level of operational safety or of environmental protection.

In the case of pipelines that might be underwater but not necessarily offshore (such as those traversing rivers and canals) additional regulatory restrictions were also liable to involve (at least in the State of Louisiana) the Louisiana Underground Utilities and Facilities Damage Prevention Law. This statute was originally passed in 1988 and amended in 1992, as part of the expressed policy of the state to promote the protection of property, workmen, and citizens in the immediate vicinity of any underground utility, and to prevent interruption of essential services which might result from damage to underground facilities or utilities. Its provisions specifically include any entity that owns or operates a public or private underground facility or utility which furnishes a service or material or stores, transports, or transmits energy, steam, oil, gases, gas, mixture of gases, petroleum, petroleum products, hazardous or flammable fluids, toxic or corrosive fluids/gases, or other items of like nature.

This legislation has had the beneficial effect of creating "regional notification centers" to handle notices of intent - especially with regard to potentially hazardous excavation. The notification centers are defined as a nonprofit association, or an organization of operators consisting of two or more separate operators, who jointly have underground facilities or utilities in three or more parishes in Louisiana, or an operator who has underground facilities or utilities in a majority of parishes in Louisiana, and which is organized to protect its members or its own installation from damage. These centers serve to notify all member operators having underground facilities in or near the site of a proposed excavation, and the operators must respond with suitable information including location, size and type of underground facility, prior to excavation.

The problem of abandoned and orphaned pipelines generated a significant amount of concern. There was general feeling that this was a subject on which there was insufficient guidance, and for which suitable courses of action were in many cases poorly defined. Mark Berman of Amoco Corporation pointed out the problems associated with remediation, liability, ownership tracking, and the conflicting issues of state/federal responsibility.

Further regulatory questions raised were (a) the effect that the new MOU will have on offshore oil and gas lessees and pipeline operators, (b) the time required for operations currently operating under DOT regulations to come into compliance with DOI regulations, (c) regulatory difficulties that may be involved in complying with new regulations, and (d) changes to the proposed MOU that would facilitate its implementation in a straightforward manner. Under the current MOU, RSPA is responsible for enforcing its design, construction, operation, and maintenance requirements on pipelines transporting hazardous liquids and natural gas "to the shore from the outlet flange at

(i) each OCS facility where hydrocarbons are produced, or

(ii)each OCS facility where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is further downstream, including subsequent on-line transmission equipment but not including any subsequent production equipment."

Also under the current MOU, MMS is responsible for enforcing its design, construction, operation, and maintenance regulations on offshore pipelines extending upstream from the outlet flange described above, into each production well on the OCS. In this regard, MMS has responsibilities for promulgating and enforcing regulations for the prevention of waste, protection of the environment, conservation of natural resources, production measurement, and safety of OCS lessee and right-of-way holder activities.

MMS has regulatory responsibilities relating to activities performed on the OCS. RSPA has responsibilities for inspecting and enforcing its regulations over all onshore pipeline systems in the country. The revised MOU is anticipated to result in MMS assuming a greater inspection responsibility for pipelines currently under DOT responsibility. MMS would integrate these additional pipelines into its current inspection program. Because the revised MOU would shift the boundaries over which MMS and RSPA are currently inspecting under their regulations, some OCS pipelines that are currently subject to DOT regulations governing their design, construction, maintenance, and operations, would become subject to DOI regulations governing such requirements. This shift in boundary for areas of responsibility - generally from the <u>first</u> OCS facility where hydrocarbons are produced, separated, dehydrated, or otherwise processed; to the last such facility - will require subsequent public rulemaking changes by both DOT and DOI. Following the final approval and signing of the revised MOU, DOT and DOI will separately propose changes to their respective regulations to reflect the new regulatory boundaries.

DOI anticipates that existing offshore pipelines that shift from DOT to DOI responsibility will not be immediately subject to MMS design and construction requirements unless: (1) those requirements were a condition of MMS approval for the right-of-way on which the pipelines are located, or (2) the pipeline undergoes major repair or modification. Design and construction requirements are those requirements that are established when the pipeline is initially designed and constructed, such as pipe specifications, design of pipeline components, and welding procedures.

Retrofitting existing pipelines to conform to different design and construction standards can involve considerable risk to personnel and be extremely costly. Therefore, DOI will be cautious in imposing changes of this type on pipeline operators here-to-fore operating under DOT design and construction requirements. On the other hand, DOI operation and maintenance regulations, such as corrosion protection, operation and maintenance plans, periodic inspections, and periodic tests are requirements that can be applied to pipelines at any time after construction. There are differences between DOT and DOI regulations with respect to these types of requirements and their compliance costs. Therefore any operator currently under DOT responsibility who is shifted to DOI responsibility after implementation of the revised MOU, will immediately become subject to DOI operation, maintenance, and inspection requirements.

It was pointed out that in some cases new technology could potentially have a major impact on regulatory issues - notably the application of Global Information Systems (GIS) techniques, which could enable modern data processing to allow significant improvements in monitoring and control of the nation's pipeline inventory, particularily if used in conjunction with Global Positioning (GPS) Systems. Norm Froomer of the Minerals Management Service outlined some of the potential uses and users, as well as costs, benefits and limitations. Pipeline inventory databases already exist to some degree, and are maintained in federal waters by MMS; by the state of Louisiana for more recent pipeline construction in state waters; and by some survey companies for the operators. Gathering and transmission pipelines are usually mapped, whereas production flow lines which are blanket permitted for the field are not mapped. As-built maps of older pipelines do not reflect the accuracy of current surveying technology and often do not incorporate rerouting during construction or possible movement of pipelines caused by mud slides. Also not all pipelines can be depicted on navigational charts due to the high concentration of pipelines and the scale limits of the charts. Not all vessels carry current charts, and many foreign fishermen are unable to read them anyway.

However new technology should enable major improvements to be made in the near future. This potential has to some extent already been incorporated into the one-call system, in which member's pipelines that transverse coastal waterways, lakes, rivers, and canals in Louisiana are already stored in a suitable database. From an informational point of view, the system relies on a keen balance between written text and the system's ability to transform map information into a workable unit - namely a polygon. Polygons are enclosed multi-sided areas which represent the utility owner's specific service area. The polygons can have as much or as little buffer area as the member sees fit, and each member's polygons are stacked like pancakes in the computer.

As the excavator's information is processed, the area of excavation is superimposed over the stack. When the area of excavation intersects with the utility's polygon, the member is notified. The system is able to correspond an address or range of addresses with a specific latitude and longitude point, and draw a box to encompass the excavation site. The computer system compares the work site with the various layers of member polygons to determine which members should be notified of the excavation. This process results from the system's ability to search, based on latitude and longitude coordinates.

There would seem to be no reason why this could not be extended offshore, with the offshore block areas used as grids in which to notify member companies in the area of any type of work that would require notice. The program would take pertinent information of the activity and location, specified by latitude and longitude coordinates or offshore block areas. The computer could then cross reference this information with the member's area and then notify the participants of the work to be performed.

Accident and release reporting requirements were another subject of discussion. The relative benefits and disadvantages of telephonic and written communications were debated, each of which had appropriate snags. It was pointed out that telephonic communication was already well established in the system of Regional Notification Centers, where telephonic notice was recorded on tape or stored into an electronic data bank by the regional center, and a record of the notice retained for a three-year period from the date of notification. In this way it was possible for a regional notification center receiving a notice of intent to excavate, to respond very rapidly by notifying the member operators having underground facilities in the potentially affected areas. The cost of the system was shared by the participatory members, including operators of underground facilities as well as the appropriate state agencies.

Coordination of information was perceived to be a problem in many instances, and Mariano Hinojosa of the Louisiana Department of Natural Resources led a discussion in this respect. The issues of damage compensation and accountability were also felt to be pertinent to this subject, although there was insufficient time to get into a full discussion of legal issues.

Revisions to the Memorandum of Understanding

Since there was still a great deal of uncertainty and interest in the provisions of the new revisions to the Memorandum of Understanding, some of the main items in the revised MOU are discussed as follows. It is important to note that compliance with the MOU does not relieve an offshore pipeline owner or operator from complying with the regulations of any other State or Federal agency :

Legislative and Regulatory Responsibilities

In general, the Department of Transportation (DOT) has the responsibility for promulgating and enforcing regulations for the safe and environmentally sound transportation of gases and hazardous liquids by pipeline. DOT administers the following laws as they relate to pipelines: (1) the pipeline safety laws (49 U.S.C. 60101); (2) the Deepwater Port Act of 1974 (33 U.S.C. 1501-1524); and (3) the Federal Water Pollution Control Act (FWPCA) (33 U.S.C. 1251-1375) as amended by the Oil Pollution Act (OPA) of 1990 (P.L. 101-380) and implemented under Executive Order 12777.

The Department of the Interior (DOI) has responsibilities for promulgating and enforcing regulations for the prevention of waste, protection of the environment, and conservation of the natural resources of the Outer Continental Shelf as that area is defined in the OCS Lands Act (OCLSA - 43 U.S.C. 1331). These responsibilities include production measurement and safety of OCS lessee and right-of-way holder activities, including transportation of oil and natural gas by pipeline. DOI also has certain responsibilities for granting rights-of-way and rights of use and easement for the construction of pipelines and associated facilities on the OCS. DOI administers the following laws as they relate to offshore pipelines: (1) the OCSLA for the production of minerals which includes their transportation to shore, (2) the Federal Oil and Gas Royalty Management Act of 1982 for oil and gas production measurement, and (3) the FWPCA, as amended by the OPA and implemented under E.0. 12777.

DOI Responsibilities

1. DOI will establish and enforce design, construction, operation, and maintenance regulations and investigate significant accidents pursuant to the OCSLA for all pipelines that connect to downstream production or processing facilities on the OCS. The DOI area of responsibility will extend from producing wells to 50 meters (164 feet) downstream from the base of the departing pipeline riser on the last OCS production or processing facility. Additionally, DOI will have responsibility for the following pipelines:

a. That portion of a pipeline otherwise subject to DOT responsibility that crosses an OCS production or processing facility from 50 meters upstream of the base of the incoming riser to 50 meters downstream of the base of the departing riser.

b. A pipeline from an OCS producing well or production or processing facility to the first subsea tie-in with a larger-diameter pipeline on the OCS. However, if the first subsea tie-in with a larger-diameter pipeline is in State waters, DOI responsibility extends to the Federal-State boundary.

c. The OCS portion of a pipeline that connects directly to a producing well or a production or processing facility in state waters.

d. The OCS portion of a pipeline from an OCS producing well that connects directly to production or processing facilities located onshore.

e. OCS production service and water lines.

2. DOI will consult with DOT during the development of regulatory requirements and will send a copy of each draft Notice of Proposed Rulemaking (NPR) concerning offshore pipelines to DOT for review at least 30 days before the NPR is published in the Federal Register. Publication of the NPR by DOI is not contingent upon the concurrence of DOT with the proposal contained in the NPR.

3. Upon approval of right-of-way applications for pipelines under DOT responsibility, DOI will provide copies of its approval letters to DOT. When DOI grants rights-of-way for pipelines which are under DOT responsibility, DOI will condition its approval on the pipelines being designed, constructed, operated, and maintained in compliance with DOT regulations.

4. The DOI will allow DOT to utilize, on a reimbursable basis, DOI-contracted helicopters for the inspection of offshore pipelines, subject to helicopter availability.

5. For pipelines under DOT responsibility, DOI will report to DOT in writing any apparent violation of DOT regulations that is identified during the course of DOI inspections.

DOT Responsibilities

1. DOT will establish and enforce design, construction, operation, and maintenance regulations and investigate significant accidents for all offshore pipelines beginning 50 meters (164 feet) downstream from the base of the departing pipeline riser on the last OCS production or processing facility, except as provided for in paragraphs 1, 1(a), 1(b), 1(c), 1(d), and 1(e) under "DOI Responsibilities" and paragraph 7 under "Joint Responsibilities".

2. DOT will consult with DOI during the development of regulatory requirements and will send a copy of each draft NPR concerning offshore pipelines to DOI for review at least 30 days before the NPR is published in the Federal Register. Publication of the NPR by DOT is not contingent upon the concurrence of DOI with the proposal contained in the NPR.

3. For pipelines under DOI responsibility, DOT will report to DOI in writing any apparent violation of DOI regulations that is identified during the course of DOT inspections.

Joint Responsibilities

1. DOI and DOT will consult and coordinate all of their respective rulemaking efforts affecting offshore pipelines. Supporting regulatory analyses (e.g. Determinations of Effects of Rules, Regulatory Impact Analyses, and information collection burdens, etc.) will also be coordinated, although the analyses will be appropriate for each agency and the industry segments it regulates.

2. DOI and DOT will coordinate all of their respective research and development projects concerning offshore pipelines.

3. DOI and DOT may perform joint inspections of pipeline segments that are subject to both DOI and DOT regulations.

4. DOI and DOT may perform joint or independent investigations of accidents involving offshore pipeline segments that are subject to either or both DOI and DOT responsibility.

5. DOI and DOT will provide each other with any agreement or MOU with any Federal or State agency concerning offshore pipelines.

6. At least once each calendar year, DOI and DOT will jointly review existing standards, regulations, orders, operating practices, and environmental and safety issues concerning offshore pipelines.

7. The DOI and DOT may, through their enforcement agencies, agree to exceptions to this MOU on a facility-by-facility or area-by-area basis. Affected parties shall be notified of such exceptions.

WORKING GROUP REPORT 2

"OPERATIONAL & OTHER DAMAGES"

Jim Lehman, Trunkline Gas Co.
Greg Schulte, Chevron U.S.A.
Phillip Myint, Chevron U.S.A.

Introduction

The session started with a general introduction to the terms of reference and workgroup agenda by Jim Lehman. One of the first items to be discussed was the National Research Council Marine Board Committee report on improving the safety of marine pipelines. This had been prompted by a number of accidents in the late 1980's which had claimed more than a dozen lives, and had raised public and congressional concern about the safety of the subsea pipeline system. Saul Bellassi, one of the members of the committee, gave a general review of the findings of the report, and presented certain specific recommendations. A full copy of these written comments on the Marine Board Report are contained in an appendix at the end of these workshop proceedings.

Discussion of the Marine Board Report

As a result of the deliberations that took place on the subject, it was generally concluded that there could not be said to be major deficiencies in the manner in which marine pipelines are constructed, operated and regulated. It would seem however, that better methods of understanding and evaluating existing inadequacies in the regulatory sector are needed to result in a comprehensive and improved safety climate. One way of achieving this could be by re-aligning agencies' procedures and responsibilities to common and comprehensive objectives. Specific conclusions were as follows.

- The regulatory agencies involved should develop a common safety data base, covering both state and federal waters, and periodically review their data requirements. The extended data base should include the information needed for risk and cost-benefit analysis. MMS has the greatest test experience and resources in data gathering.

- Safety regulations should be based on sound risk and cost-benefit analyses. Specifically, regulatory agencies should agree on a consistent risk management strategy for setting priorities about human safety criteria, and about the use of cost-benefit analysis for the reduction of property and environmental damage.

- It is desirable to make better use of inspection resources and help integrate enforcement of MMS and OPS marine pipeline safety regulations. It is recommended that enforcement of OPS regulations offshore be performed by the MMS, through an interagency agreement or redefinition of the Memorandum of Understanding that defines the jurisdictional division between OPS and MMS. Such a system would continue OPS's role in regulating offshore pipelines by bringing to bear MMS's greater resources.

- Marine pipelines already constructed should be exempted from federal or state requirements for the use of currently available smart pigs for external or internal corrosion detection. New pipelines running from platform to platform or platform to shore should be designed to accommodate smart pigs whenever reasonably practical.

- MMS should coordinate an effort by appropriate federal and state regulatory ageneies and industry to establish a system through which leaks detected by third parties can be reported to a single agency or notification center with continuous coverage around the clock. This one central location should have a comprehensive data base permitting easy identification of the operator of any marine transmission or production line based on the reported sighting location. Pipeline operators, in turn, should have 24-hour telephone numbers or a means of immediately contacting all other pipeline and platform operators who must take action.

- In areas where supply and service vessels operate adjacent to fixed platform installations associated with high densities of pipelines or flowlines, permanent mooring systems should be considered. Platform operators should be required to provide detailed and timely information to vessel operators on the configurations of local pipelines or flowlines. New pipelines adjacent to platforms should be installed whenever possible in well defined "corridors."

- Geotechnical studies of soil conditions, with sampling at intervals determined by local site conditions, should be required as a condition of marine pipeline construction permits. Permitting and regulatory agencies should work with industry to develop criteria for specific gravities of marine pipelines in varying soil environments.

- To provide baseline data for subsequent depth of cover and bottom status surveys, newly installed pipelines should be surveyed, and their depths of cover recorded, with reference to Global Positioning System locations.

- All agencies involved in the permitting of pipelines crossing shorelines should require the use of the directional bore installation method wherever feasible.

- In waters less than 15 feet deep, periodic depth-of-cover surveys in the Gulf of Mexico should be scheduled according to the specific local shoreline and seabed dynamics, and the passage of severe storms.

- Pipeline operators and regulatory and permitting agencies should conduct studies to determine the appropriate standards for initial depth of burial under various shoreline and seabed conditions, using the results of the recommended periodic depth-of-cover surveys.

- Pipeline abandonment standards and regulations should include a requirement for a one-time inspection at the time of abandonment to verify that abandonment requirements were met.

Applications of Safety "Pictographs"

There was discussion led by Ted Kinne of INGAA, on the application of offshore pipeline safety pictographs. The INGAA foundation has been responsible for establishing a continuing education program to enable appropriate persons to recognize a gas pipeline emergency. One of the objectives was to design signs with universal symbols that communicate safety messages immediately and accurately, without being limited by the lack of a shared language. The messages conveyed should be easily and immediately recognizable and informative to an array of marine operators. A more general mission of the program is to implement additional communication strategies to satisfy the informational needs and understanding between pipeline operators and other maritime activities.

Unlike inland underwater crossings, offshore pipeline locations can not be identified by line markers or river crossing signs. Prudent mariners will avoid damaging pipelines to the extent that is within their control, but without knowing exactly where these pipelines are, encounters will continue to occur. Communication and awareness are the key issues that will help reduce or minimize the consequences of damage.

A comprehensive pipeline safety awareness program for mariners does not exist at present, but safety stickers, brochures, pamphlets, and other educational material have proven successful at reducing third party damage for onshore pipelines. The efforts to develop a pictograph approach to raise the level of awareness concerning underwater pipeline safety is now beginning to receive wide acceptance. Previously pipeline operators for the most part had no idea how to convey a safety awareness message concerning the danger of underwater pipelines.

The results of the study confirmed the recognizability and usefulness of well designed signs. Other observations were that signs in cabins or wheel houses might be a good general reminder to operate vessels safely. Fishermen initially claimed that they did not tie to platforms, but on reflection said the practice does take place, and thought a don't-tie-up-here sign placed on a platform was a good idea. Signs indicating don't place the leg of your rig here; don't drive pilings here; don't dredge here, etc.; were recognized as good reminders by such operators.

Some shrimpers would like charts at a scale of approx. 60 to 100 miles to indicate the position of pipelines. Other more sophisticated operators want information on the locations of pipelines and other obstacles defined by Loran coordinates expressed in time and distance. Some use "hang books" and Loran coordinates to record obstacles encountered below the surface during fishing operations, and suggest that "hangs" be marked either by Loran coordinates or by latitude and longitude. Sophisticated operators can also use their sonar color screens to read the density of whatever is below their vessels - i.e. fish, pipelines, mud, sand, coral etc..

Comments from the focus group indicated that no agency is universally believed to be the best focal point to report problem areas where pipelines have become exposed, have been struck or snagged, or constitute hazards. From the point of view of fishermen, their past relationship with the Coast Guard may make this an undesirable choice.

Offshore One-Call System

Partly as a follow-on from these comments about the desirability of a centralized and coordinated reporting system, a discussion took place on the viability of an offshore one-call system, and a presentation was made in this regard by Bill Bertges of the Southwest Region Office of the Department of Transportation. It was pointed out that damage prevention programs have typically been directed at minimizing the occurrence of outside force damage or excavation type incidents for onshore pipelines. These programs consist of a multitude of actions that are mandated by the federal Department of Transportation gas and liquid pipeline safety regulations. Present requirements do not however include pipelines located in offshore locations. This probably was due in part to the historically low risk and frequency of occurrence of outside force failures, and in part to the impracticality of identifying site specific offshore locations and a communication system for notification at the time of the original rule-making.

It was now believed to be feasible however to apply the latest technology of computerized mapping systems and global positioning systems, to a mariner pipeline safety awareness program. In fact some existing pipeline inventory databases do exist, and are maintained in federal waters by MMS, for more recent construction in state waters by the state of Louisiana, and by some survey companies for certain operators.

At present, gathering & transmission pipelines are usually mapped, whereas production flow lines (which are blanket permitted for the field) are not mapped. As-built maps of older pipelines do not reflect the accuracy of current surveying technology and ofter do not include re-routing during construction or movement of the pipeline caused by mud slides. Also, not all pipelines can be depicted on navigational charts due to the high concentration of pipelines and the scale limits of the charts. Not all vessels carry current charts, and many foreign fishermen are unable to read them properly.

Although there would be shortcomings, such as responding to false alarms, these should be greatly outweighed by the advantages, as the consequences to the operator can be very serious. Damage can be quite subtle, and could be a dent, gouge, or coating defect to the pipeline that will lead to failure at some future date if not detected. It need hardly be reminded that major spills can adversely affect the environment, particularly the shoreline or fish and wildlife estuaries. Catastrophic gas ruptures can result in major loss of life, and media press coverage can be devastating to a corporation's public image, not to mention revenue losses, costs of underwater repairs, product loss, spill response and remediation, penalty assessments, legal costs and higher insurance premiums.

Support for an effective system should be relatively widespread. Fishermen have for the most part coexisted successfully with the pipeline industry, as they know that the platform structures have benefited them. Underwater obstructions however, are a concern to mariners because their vessels may suffer consequences that are not be recoverable, even though they can claim from federal and state fishermen gear compensation fund programs. Damages can include hull or prop damage, damaged nets, and lost anchors, and the Louisiana fishermen gear fund for instance has a $5,000 dollar limitation, so that the mariner usually loses more than he gains even when a claim is approved.

It would be of great assistance to this industry if obstructions could be catalogued and possibly remediated. At present the compensation fund programs do not site verify the existence of underwater obstructions when a claim is made. In many instances there may be numerous claims at a given location. No effort is made to notify operators in the vicinity of the reported hang to investigate for damages or identify the obstruction. Hangs in federal waters are depicted on navigational charts only after MMS has determined that oil or gas facilities exist at that location.

The notification process could begin with the mariner, who would either have observed or have caused a leak, or be hung upon or have struck an underwater obstruction, or have collided with a structure. Most vessels operating in the Gulf are equipped with both marine radios and Loran or GPS devices, and could provide location coordinates, and could either call the Coast Guard or a 1-800 number if access to a radio telephone or cellular phone was available. Since the USCG's responsibility includes responding to and investigating leaks or spills, and also reporting hazards to navigation through its Notice to Mariners program, this may be the most convenient option.

Once notification was received by the center, a determination of facilities on record at that location would be made based on the latitude and longitude coordinates provided by the mariner. This determination would include those member companies identified by a computer search. The notification would then be electronically communicated to each affected member regarding the leak, obstruction, or collision.

After notification was received, the operator would have certain options available in determining the best course of action, including implementing an investigation to determine the pipeline status, activating an emergency plan, or doing nothing if the information provided clearly indicated that the member's pipeline could not be the leak source. If there is no leak, but information suggests that the operator's pipeline may have been damaged, one could gather more information. Other possible actions include running a sonar survey to determine if the pipeline is exposed or if disturbance of the seafloor is indicated near the pipeline, conducting a diver inspection, running a sizing or caliper pig through the pipeline to determine if the pipeline has been dented or gouged, marking the pipeline's location with a buoy if it is exposed or constitutes a hazard to navigation, or reinforcing or repairing the pipeline if damage has been determined.

David Frey of the Louisiana One-Call system also discussed the current state of the art in computerized mapping technology as used on-shore. With the advancement of computerized one-call systems, extensive development of mapping programs has taken place. The challenge is in finding an effective way to link the computer system with the raw mapping data. In Louisiana, the mapping data is provided by tiger files, which contain the mapping portion of information provided by the census bureau. The new generation of one-call technology relies on a keen balance between written text and the system's ability to transform map information into a workable unit - namely a polygon, which are enclosed multi-sided areas representing the utility owner's specific service area. The polygons can have as much or as little buffer area as the member sees fit. Each member's polygons are stacked like pancakes in the computer. As the excavator's information is processed, the area of work is superimposed over the stack. When the area intersects with the utility's polygon, the member is notified.

The system is able to correspond an address or range of addresses with a specific latitude and longitude point, and draw a box to encompass the site of interest. The system compares the work site with the various layers of member polygons to determine which members should be notified, resulting from the system's ability to search based on latitude and longitude coordinates. This could be extended to a map data base that could consist of latitude and longitude coordinates and/or offshore block areas. The offshore block areas could be used as grids which the computer would then cross reference in order to notify member companies in the area.

Present & Future Surveying Technology Offshore

On the subject of surveying offshore, since this was clearly an important component of damage prevention and mitigation, some discussion took place on the developments in surveying technology. The first surveys near-shore utilized land based survey control and visual survey equipment. As offshore platforms were installed, survey control was extended from land to the offshore installations. In 1955 and again in 1963 the U.S. Coast and Geodetic Survey ran a triangulation/trilateration net along what were at that time the most southerly structures in the Gulf, followed by a Doppler survey in 1972 that was used to tie in private surveyor's work.

Surveys beyond the line of sight were performed using radio positioning in three possible ways :- (a) Low frequency hyperbolic systems that produce longer ranges with less accuracy, (b) Mid frequency systems that produce greater accuracies with less range, (c) Microwave systems that produce higher accuracies but limited to radio line of sight. Satellite positioning became possible after the development of the Navy TRANSIT Positioning System which was used by the Polaris submarine fleet, and was made available to the public in 1969. Subsequently the Department of Defense started experimenting with the Global Positioning System (GPS) in 1978, although this remained in an experimental stage for many years. In 1987 STARFIX was developed commercially using the geosynchronous satellites used for world wide communications, and was the first satellite positioning system capable of providing continuous positioning 24 hours a day over the North American continent. The system was limited to the area covered by the footprint of the satellites, which is basically North America and its coastal waters.

Mr. Shuble Tenney of John Chance and Associates described some of the latest methods in use. As developed by the Department of Defense, GPS now consists of 24 satellites in multiple orbits that give continuous positioning world wide, although the signals available to the civilian user are degraded and accuracy is reduced. However the use of differential techniques allows position computations with a high degree of accuracy and repeatability. This method continuously tracks all GPS satellites in view from precisely surveyed reference sites, and compares the range from each satellite to the theoretical range, to obtain a difference that can be used as a range error correction.

It is possible to use multiple reference stations to calculate differential corrections, and the range errors can then be shipped over the STARFIX satellite uplink to the user, to be applied to the position solution at that point. There are numerous methods of determining differential corrections from a single reference site or numerous sites, so as to obtain accurate positioning of offshore drilling rigs, pipelines, platforms, seismic vessels, and dive boats etc.. This can also be used to obtain information from remote sensing devices to map the seafloor and gain information on potential hazards to offshore operations.

Such information is now also being used in conjunction with GIS data base creation, although it is believed that Amoco Pipeline Co. is currently the only company that has extended its data base offshore. A GIS data base for a gas transmission company is generally setup in what is called AM and FM format, where AM stands for automated mapping and FM for facility mapping.

It was pointed out that there has been a number of accidents of drill rigs hitting pipelines in the last 18 months. It was suggested that a major contributory factor was that none of the rigs had survey equipment on board, so that the operator could not really know where his rig was in relation to the pipelines.

Mobile Offshore Drilling Units (MODU's)

Some remarks were made regarding improving the safety of mobilizing mobile offshore drilling units (MODU's) in the vicinity of pipelines and other obstructions. Robert Ettle of Diamond Offshore Drilling noted that drilling contractors who own or operate MODU's are eager to avoid contact with pipelines to preclude the possibility of injury, property damage or environmental damage. In addition they want to avoid contact with any wreckage, debris or abandoned equipment (e.g. wells, jackets, pipelines) which might damage the footing (either spud can or mat type).

Damage to pipelines from MODU's can result from three general causes:-

- Lack of knowledge of the pipeline on the part of the mover in charge of the MODU.

- Lack of knowledge of the location of the MODU relative to the pipeline and other obstructions.

- Jacking MODU's out of the water or anchoring MODU's under the stress of severe weather, as well as dragging anchors during severe weather.

The first two causes could be considerably improved. The last cause can probably not be eliminated, but better knowledge of pipeline location can reduce the likelihood of or severity of damage. The pipeline maps available for purchase from MMS were believed to be an excellent starting point, but are not necessarily timely and must be ordered on an occasional basis by the user. The user has no way of knowing when a particular map has been revised. It would be helpful if MMS could make these maps available in both hard copy and digital form on a subscription basis whereby updated maps are distributed to subscribers in an automatic, expedient manner. Also, abandoned wells should be shown on these maps.

Seafloor Obstruction Survey

The desirability of having up-to-date information on the seafloor conditions was noted, particularily regarding the positioning of jack-up MODU's. Those units which have no propulsion are affected by the current, wind and to a smaller degree, by the seas while being positioned. The tow vessels are also affected by these factors, and they cannot be held in an exact position. Thus the jack-up MODU can be positioned with even less precision than the tow vessels until the footing reaches the seafloor. The only way to steady and control the movement of the jack-up is to lower the footing to the seafloor and drag the footing through the upper few feet of sediment. Thereafter, the movement of the jack-up can be controlled by pulling with the tugs against the drag of the footing. During the 15 to 20 minutes that it takes to lower the footing from a typical bottom clearance of 15 to 20 feet to seafloor penetration (normal jacking speeds are 1 to 1.5 feet per minute), the jack-up can only be held in an approximate position because of wind and currents. To do this safely, an area of at least 500 feet wide by 600 feet long, away from surface obstructions such as a platform, is normally needed.

To provide a clear landing area or path, a Seafloor Obstruction Survey is therefore desirable. The Lease Survey required by Notice to Leases (NTL) is more than adequate if it is still available and still current (i.e. if there has been no drilling or construction near the proposed location). If a Lease Survey or Site-Specific Survey are not available, or do not reflect current conditions due to activities since the survey was completed, then a Seafloor Obstruction Survey (NTL 83-3; III, c, 2, c), should be completed to positively identify the location of any obstructions (pipelines, debris, wreckage, wells, etc.). It was believed that the most suitable survey instrument for this purpose is side-scan SONAR. It was recommended that NTL 83-3 should be revised to require a Seafloor Obstruction Survey of at least 300 meters by 300 meters to reflect current conditions.

Regarding semi-submersibles, the Seafloor Obstruction Survey should cover an area of at least 150 meters beyond the planned anchor locations. It was noted when towing jack-ups from one location to another, the tugs are all towing from the jack-up's bow. Upon arrival near the new location, the tugs must be shifted so that one is on each corner. Under past practice, the mover would often lower the footing to the seafloor one quarter to one mile from the location in order to steady the jack-up. This steadying of the jack-up makes the maneuvering of the tugs during un-tieing and re-tieing much easier. However it has resulted in pipeline damage, and it was recommended that this practice be discontinued.

On-Site Map and Marking of Obstructions

Good practice in moving jack-up MODU's is that a plat be prepared with a minimum scale of 1:72,000 depicting the location of the proposed activity (including anchor patterns) as well as all pipelines, flow lines and other obstructions. Copies of this plat should be provided to key personnel on all drilling units, dredge barges, pipeline-lay barges, and all anchor handling vessels associated with the activity. It was suggested that NTL 83-3 be revised to require that the plat cover an area at least as large as the minimum Seafloor Obstruction Survey required for the activity. Electronic navigation positioning systems are also highly desirable on such vessels to use such information effectively. Otherwise it is necessary to rely upon visual observations of surface facilities unless the obstructions are marked by buoys or by a surveyor. The marking of obstructions should be required in more cases.

It is desirable that all pipelines and other obstructions within the area to be covered by a Seafloor Obstruction Survey should be visually marked. Additionally any live pipelines within 250 meters of a proposed jack-up MODU, open (unobstructed) location, or within 150 meters of the approach end or left or right sides of a jack-up MODU landing path on a location with an existing structure, should be visually marked. This marking may be done by physically buoying the obstruction or by displaying the obstruction on the graphic presentation of an electronic navigation positioning system.

Specific recommendations with regard to the moving of MODU's were :-

- Updated pipeline maps (both hard copy and digital) should be available on a subscription basis whereby they are distributed to subscribers both automatically and promptly.

- Rig movers should not lower jack-up legs and tag bottom in order to hold steady while shifting the positions of attending tow vessels, unless shown by a precise electronic navigation positioning system to be at a location surveyed clear of pipelines.

- If survey data regarding seafloor obstructions are not available, or are not current (drilling or construction has occurred since last survey), a new Seafloor Obstruction Survey using side-scan sonar should be performed. This should cover the planned landing path or area where the seafloor may be disturbed by footings, and be a minimum of 300 meters by 300 meters. For semi-submersibles, the survey should cover at least 150 meters beyond planned anchor locations.

- The requirement for a plat depicting all obstructions in the area of the proposed activity should be continued, and should cover the area which would be required for a Seafloor Obstruction Survey.

- The area where obstructions should be marked for jack-up MODU activities should be expanded to include all obstructions within the 300 meter by 300 meter minimum seafloor obstruction area. In addition, any live pipelines which are near this area should also be marked.

Hurricane Andrew

In the category of natural disasters, a number of participants spent time discussing the information relating to the passage of Hurricane Andrew over the Gulf of Mexico, which began as a tropical depression in the Atlantic Ocean on Monday, August 17, 1992. In the afternoon and night of Tuesday, August 25, the eye of the storm passed though one of the most intensively developed oil and gas areas of the Outer Continental Shelf (OCS). According to data published by the National Hurricane Center, the intensity of the storm as it reached the OCS oil and gas fields was a full Category 4 storm with sustained winds of 140 miles per hour with gusts reaching 165 miles per hours. Significant wave heights were estimated at 35 to 40 feet.

Since the track of hurricanes is so unpredictable, the oil and gas industry routinely curtails most operations in the Gulf of Mexico whenever hurricanes approach. An estimated 26,000 people were evacuated for Hurricane Andrew. The MMS policy requires operators to curtail all oil production and significant gas production from fields evacuated during a hurricane. Gas platforms and pipelines are allowed to operate after field evacuation only if operations can be monitored remotely and only until the approach of the storm becomes imminent.

Most oil stored offshore is pumped away and most oil pipelines depressurized prior to evacuation. Gas pipelines are often left pressurized so that leaks can be easily detected upon returning to the field. The majority of operators conduct fly-over inspections before trying to bring their fields back on production after storms. If there is no obvious signs of pipeline damage such as bubbles, loss of pressure, or severe riser damage then attempts may be made to reactivate the pipelines.

Initial Damage

The initial reports were of obvious above-water damage to platforms and pipeline risers. Platforms were bent, and in many cases, toppled along with any pipeline risers attached to the structures. In fact, the majority of pipelines affected by the hurricane were damaged when the structures they were attached were damaged. According to records compiled from a number of sources, there were only 11 spills of oil reported due to hurricane damage. Of these, only one directly involved a pipeline, namely a 20-inch pipeline in South Pelto Block 8 which was pulled apart when an anchor from a drifting semi-submersible drilling rig snagged the line. The pipeline damage and pollution was not discovered until efforts were made to reactivate the pipeline following the hurricane, and resulted in an estimated 2,000 barrel spill.

The estimate for the other 10 reported slicks and sheens totalled only about 500 barrels, bringing the total reported oil spilled to an estimated 2,500 barrels. This low value can be attributed to the proper functioning of installed safety equipment. Small volumes of oil that leaked from damaged equipment and pipelines during the hurricane would have dissipated and weathered before crews returned offshore.

Summary of Damage

The keynote presentations have already discussed quite a bit of the effects of the hurricane, and extra presentations were made in this respect by Mike Brickey of Trunkline Gas Co., Warren Williamson of Minerals Management Service, and Tom Angel of Submar. Some interesting results were noted.

A total of 25 operators and pipeline right-of-way holders reported damage to pipelines and/or pipeline crossings. Only eight operators reported damage to crossings and/or tie-ins. A total of 496 pipelines were damaged during Hurricane Andrew, representing 19% of the pipelines in the 85-mile wide path of the hurricane and approx. 8% of the total number of pipelines in the Gulf of Mexico OCS at that time. Most of the damage was caused by connecting structures, and was detectable with above-water inspections. Only 7.5% of the damaged pipelines were revealed by underwater shallow water surveys as opposed to above-water surveys. In general, the inspections conducted appear to have been successful in revealing damage to pipeline tie-ins and crossings.

A greater percentage of smaller sized pipelines in the hurricane's path were damaged than larger size pipelines. A greater percentage of pipelines in water depths between 20 and 50 feet were damaged than pipelines in deeper or shallower water. It was also very interesting that a greater percentage of newer pipelines, aged 20 years or less, were damaged than older pipelines.

Only one operator reported that anodes were lost during the hurricane, and these were replaced. OCS oil and gas pipeline damage followed the usual pattern associated with hurricanes in the northern hemisphere - the heaviest damage occurred north and east of the storm track. It also appeared that pipelines connected to single-well platforms were more likely to be damaged because the structures were more likely to be damaged.

Inspection methods used included divers, ROV and side scan sonar. The general scope of inspection was typically risers out to 500 feet, crossings, and tie-ins. The detailed scope of inspection mostly included general pipeline condition, structural damage, anode damage, pipeline burial depth, pipeline crossing condition, tie-ins cover condition, and debris on or near the pipeline. Some companies used side scan sonar and magnetometer surveys to locate displaced pipelines. Mesotech side scans were also used on some pipeline crossings.

Comments Concerning Storm Damage Prevention and Detection

Comments concerning storm damage prevention and detection were as follows:-

- The major reported incident of pollution occurred when an oil pipeline was being reactivated following the hurricane before the pipeline damage was known. Oil lines should be depressurized and, ideally, should be filled with gas or water before evacuating the field. Measures should be taken to fly over the path of oil pipelines as they are being brought back into service slowly, following a major storm, in order to detect any leaks.

- Breakaway joints in general worked, based on the reports of breakaway joints separating as designed.

- Gas pipelines should remain pressurized at a reduced pressure so that leaks can be easily seen following a hurricane.

- Damage from rigs and other third party equipment was a problem. More work has to be done to determine how this problem can be prevented or mitigated.

- Concrete mats used to cover crossings and subsea tie-ins should survive hurricane forces better than sand bags.

- Based on the damage reported, the 85-mile wide area outlined in the NTL may have been too broad. Many shallow-water blocks in this 85-mile wide path had no pipeline damage reported. However, there was damage reported in blocks outside this area. This may indicate that the MMS should not impose a general mandatory requirement for post-hurricane shallow water damage surveys but should require surveys on a storm-by-storm and lease-by-lease basis.

- Magnetometer and side scan sonar surveys give the best overall indication of pipeline displacement and crossing/tie-in damage.

Corrosion

In regards to prevention and mitigation of damage, some time was spent on the discussion of corrosion control, and presentation were made in this regard by Bob Winters of TGP Gas Transmission Co. and Clark Weldon and David Kroon of Corrpro Inc.. Since the consequences of an offshore corrosion failure can be very serious, cathodic protection has become a universally applied technique for mitigating corrosion, typically by providing cathodic protection with bracelet anodes of zinc or aluminum. Impressed current systems at platforms or onshore are also used, as well as hybrid systems which employ a combination of the two techniques.

The most widely accepted method of evaluating cathodic protection on pipelines and structures is through the use of potential measurements. Potential measurements on offshore pipelines have traditionally been recorded only at readily accessible locations such as platform risers, wellheads, and test stations located near shore. Divers can be used to take potential measurements on submarine pipelines at discreet locations, but this procedure is much too costly to use extensively. Monitoring of pipeline cathodic protection only at platforms or shore installations provides limited information. It is possible that serious corrosion can be occurring on a pipeline even when potentials at a riser or test station satisfy the criteria for cathodic protection.

The importance of effective corrosion surveys at this stage in the aging of the pipeline infrastructure was pointed out. Many existing offshore pipelines are reaching the end of their cathodic protection system design lives. It is possible, but expensive, to retrofit with additional protection. In the case of deep water pipelines, the remotely operated vehicle (R.O.V.) may be the only effective way to implement corrosion survey, inspection, and control. Computerization of survey data acquisition, processing and management has greatly improved the means for controlling the corrosion techniques used today. These include close interval pipeline surveys, modeling of platform cathodic protection and inspection data management systems.

In shallow water, a portable marine magnetometer may be used to locate the pipelines which can then be marked at regular intervals using temporary buoys. Downline position may be approximated using wire distance or more accurately using electronic distance measuring equipment. Otherwise it is preferable to use a surface positioning system such as Syledis or Star-fix to position the survey vessel. Ideally the surface positioning system can be electronically integrated with an acoustic positioning system, to provide an integrated positioning system giving towed fish position relative to the as-built coordinates of the pipeline. Where as-built coordinates are accurate, an integrated positioning system allows the towed fish-to-pipeline distance to be maintained within 15 meters in most cases.

Some overall conclusions on corrosion techniques were as follows :-

- On a well coated pipeline equipped with bracelet anodes, anomalies such as missing individual anodes and areas of minor coating damage are typically detected only when the measurement electrode is within approximately 3 pipe diameters from the anomaly. The poorer the coating quality and the higher the anode output, the greater the electrode-to-structure distance at which an anomaly is detectable. Except in brackish or fresh water and/or pipelines receiving impressed current, anomalies in bracelet anodes and minor coating flaws are not detected using the towed fish/trailing wire technique. Depending on coating quality and depth of burial, these anomalies may be detected using R.O.V. aided techniques.

- When electrode position is maintained within approximately 15 to 20 meters (which is generally the case using a towed fish and trailing wire) "long line effects" such as those caused by areas of major coating damage, electrical interaction between the pipeline and continuous platform jackets, and large "point" current sources such as anode sleds or impressed current sources are readily detected.

- Comparison of data collected using the towed fish/trailing wire method with data recorded using an R.O.V. aided method on the same pipelines, has shown that the overall measured potential levels were approximately the same (+20 mV.). The primary difference was in the detection of anomalies such as minor coating flaws and individual bracelet anodes. Fortunately, in seawater and saturated muds, where resistivity values are very low compared to land based pipelines, protective current from bracelet anodes is easily delivered to coating flaws several thousand feet away. This effect, coupled with minimal electrolyte IR drop at the cathode caused by low resistivity, results in potential profiles on typical submarine pipelines that show little localized variation in potential at coating holidays. Even with E.F.G. measurement, accurate calculation of anode output is extremely difficult if not impossible, using existing survey techniques, particularly on partially or totally buried pipe. A number of variables must be considered including electrolyte resistivity, degree of anode burial and anode sensor geometry.

- Electric Field Gradient (E.F.G.) measurements are also useful for determining location and relative severity of coating holidays, and for locating disfunctional anodes. The measurements can also provide a useful comparative estimate of anode outputs. E.F.G. measurements are most valuable when used in conjunction with P/E potential surveys or with direct P/E potential readings taken at frequent intervals along pipelines.

WORKING GROUP REPORT 3

"RELIABILITY DESIGN FOR NEW AND EXISTING PIPELINES"

Ron Hoepner, Transco Gas Pipeline
John Robinson, Mobil Exploration

Introduction

This was a well attended session, with a considerable amount of audience participation. As part of the overall consideration of reliability analysis and design, an overview of marine pipeline accident statistics was presented by Joseph Caldwell, who pointed out that statistics on the operational experience of equipment or function are key elements in looking back on performance and looking forward for improvement and change. Both the detail and comprehensiveness of the data is important, although for both onshore and offshore pipelines, a good system for collection of operational data does arguably not exist.

Several attempts have been made to assess the data that is available, but in most cases the data is not comprehensive enough to draw positive conclusions. Industry has tended to resist in providing pipeline failure information to government agencies, and the agencies have not taken a strong stance in requiring comprehensive information. Thus the "watered down" information tends to be very basic and does not provide enough detail to make sound decisions on an industry wide basis. A few companies probably have kept statistics and information on individual systems, but in many cases their experience would not be applicable industry wide. The recent review of the safety of marine pipelines that was commissioned by the MMS and the DOT/OPS to the Marine Board of the National Research Council (1994) is probably the most comprehensive study to date.

This generally concluded that data collected by federal and state agencies was inconsistent and incomplete - each agency collecting primarily data that applied to their particular purposes, without attempting to assemble a coordinated data base. In this review, the committee relied basically on studies by Woodson (1991) for the NRC and Mandke (1990) of Southwest Research Institute who analyzed MMS pipeline failure data from 1967 to 1987 for the Gulf of Mexico, and Broussard of Tenneco who analyzed pipeline failure reports to OPS for the period 1984 to 1990. Joseph Caldwell presented additional information extending Broussard's study through 1994, using OPS data, which showed that the various causes of failure could be classified as follows :-

- 50% of failures are caused by corrosion (this is consistent with North Sea experience), the rest being caused by maritime activities (anchors, nets, trawles, and vessel contact).

- There appeared to be no clear correlation between the product carried in the pipeline and the cause of failure.

- 70% of corrosion failures occurred in lines of 6 inches or less in diameter.

- 78% of corrosion failures took place at platforms, either in risers (splash zone) or at an adjacent seabed (e.g. pipe bends at bottom of riser).

- A relation between failure rates and length of service could not be established.

As far as losses resulting from these failures are concerned, six incidents resulted in all the fatalities and serious injuries since 1967. Pollution of the environment was probably the second biggest concern to the public, and it was noted that :-

- 95% of pollution resulted from maritime activities

- 90% of all marine pipeline spills, by volume, was due to anchor damage.

- In the period 1967 - 1987, 80% of OCS pipeline spills were less than 10 barrels in size. Only 20 spills between 1971 and 1990 exceeded 50 barrels.

- 85% of the pollution from pipelines for 1967 - 1990 was accounted for by the 4 largest spills, all caused by anchor damage. 98% of the pollution was produced by the 11 largest spills, all but one caused by vessels.

Since there is no common safety data base covering state and federal waters that can be analyzed on the long term to improve the design and operating practices of marine pipeline systems, it was suggested that the responsible federal and state agencies should develop with the cooperation of industry, a comprehensive reporting, storage and analysis system to be used in evaluating current regulations. In order to obtain comprehensive detailed information, follow-up and supplementary filing of additional information is desirable. Industry could use the same information to monitor operating practices and guide them in future design of more efficient and safe pipeline systems.

Stability of Pipelines

A discussion took place, led by James Hale of Brown & Root, on the subject of stability of pipelines on the seabed, as the amount of concrete necessary for pipeline stabilization is an issue which has generated much interest. Hydrodynamic forces acting on marine pipelines can be generated by storm waves and a number of different current types (storm, tidal, density gradients, geostrophic, or eddies from major circulatory systems such as loop currents). Unless pipelines are adequately designed, these hydrodynamic forces can cause excessive pipeline movements which may damage the pipe, its coating(s), or adjacent structures. To prevent this, marine pipelines are stabilized, usually by applying a concrete weight coating.

The design of on-bottom stability has gone through a number of changes in recent years. It was traditionally based on the static balance between applied hydrodynamic forces and resisting soil forces. Hydrodynamic forces were computed using the familiar Morison equation with drag and lift force coefficients for pipes in steady flow. Soil forces were typically characterized as a frictional force with coefficients based on sliding pipe tests or simple foundation theory. Design sea state conditions were typically represented by a single regular wave height and period (e.g. as described in 1976 DNV Rules for Pipeline Design). For oscillatory flow conditions, this method has now been shown to be inaccurate due to its simplistic models for hydrodynamic and pipe-soil interaction. However, the method has been successfully used in many parts of the world for many years, and is generally felt to yield conservative designs.

In the late 70's through the mid 80's, under the sponsorship of the Pipeline Research Committee at the American Gas Association (PRC/AGA) and other industry groups (PIPESTAB and JIPSTAB), there has been a re-definition of on-bottom stability design of submarine pipelines. Hydrodynamic research indicated that peak hydrodynamic coefficients in oscillatory flow could be substantially larger than for steady flow conditions. In addition, the time variation of hydrodynamic forces was poorly described by the Morison equation (for pipes close to a boundary). The higher hydrodynamic coefficients never gained widespread use because industry recognized that their use with traditional design methodology would lead to unrealistic weight coating requirements.

Further recent work on four key areas - hydrodynamic forces, soil resistance forces, analysis tools, and design guidelines - has now shown that the larger hydrodynamic forces could result in some pipe movement. However it also indicated that small pipe movements will cause additional pipe embedment, provided bottom sediments are not too dense (non-cohesive soils) or too stiff (cohesive soils). This added embedment causes a substantial increase in soil resistance, which limits the pipeline movement and in fact can stabilize the pipe. This suggests that during building seas and storms, initially unstable pipes may become more stable.

It is now recommended that a more rigorous approach to on-bottom stability design incorporate :-

- use of the entire design sea state rather than a single wave from that sea state

- realistic hydrodynamic forces which accurately describe not only peak hydrodynamic forces but the temporal variation of those forces

- realistic pipe-soil interaction including two soil resistance terms (frictional and non-frictional) and pipe embedment into the soil as a function of loading history (i.e. cyclic hydrodynamic loadings).

It was noted that although these results were initially incorporated into several tools not available to the public, they are now featured in the PRC/AGA software and design guidelines and in Veritec's RP-E305.

Factors of Safety

It was noted that the definition of safety factor for such design did not necessarily follow conventional engineering practice. For design procedures which allow minimal pipe movement, the factor of safety is normally defined as the hydrodynamic force divided by the available soil resistance, calculated at the instant of least stability during wave passage. In traditional design, it has been common to use a factor of safety from 1.0 to 1.1. When a more rigorous design approach is used in conjunction with accurate design sea state and soil data, a safety factor of 1.0 is appropriate, as the design still remains conservative if conservative values for soil parameters are used with a conservative estimate of the design storm.

For design procedures which allow large pipe movements (which are not often used for design), there is no safety factor. Instead, pipeline safety is determined from pipe movements and stresses seen in the analyses, and a statistical evaluation of those movements and stresses.

Alternative Stability Methods

Concrete coating is usually the most cost effective method to achieve pipeline stabilization. However, in some cases other methods must be employed, typically if :-

- concrete requirements would preclude installation using conventional equipment
- the pipeline is to be installed using the reel method
- concrete requirements would excessively complicate handling and/or transportation of the pipe
- the pipe is already in-place and found to be unstable.

Under these circumstances, it was recommended that alternative other methods of pipeline stabilization should be considered. These are very case specific and sensitive to geographic location and availability of materials and equipment, and tend to fall into two categories. Firstly those that remove the pipelines from the hydrodynamic forces acting on them, namely :-

- trenching (with or without backfilling)
- directional drilling
- armor rock covering

Secondly those that anchor the pipeline to the seabed at specific points, such as :-

- concrete mats or grout filled bags
- mechanical anchors (screwed-in or drilled-in)

In this respect, a discussion then followed on the merits of Horizontal Directional Driling for trenchless installation, as this process presents designers and contractors with significant advantages in installing pipelines beneath a wide range of surface obstacles. However in order for these advantages to be realized, creative engineering efforts must be properly applied in advance of and during construction. Presentations were made by Buzz Hair of Louis J. Capozzoli & Associates and J.D. Hair from Tulsa, Oklahoma, concerning the issues involved in designing a drilled installation as well as contractual and construction monitoring considerations. Significant issues include site investigation requirements, drilled path design, construction activity impact, pipe specification, and contractual considerations including allocation of unknown subsurface condition risks.

Horizontal Directional Drilling (HDD)

This process was originally utilized primarily in constructing river crossings for high pressure cross country pipelines, but is now being increasingly used for on-shore approaches, and is potentially applicable in many situations. Installation by HDD is a two-stage process. The first stage consists of drilling a small diameter pilot hole along a designed directional path. The second stage involves enlarging this pilot hole to a diameter which will accommodate the pipeline and pulling the pipeline back into the enlarged hole.

Pilot hole directional capability is accomplished by using a non-rotating drill string with an asymmetrical leading edge which creates a steering bias. If a change in direction is required, the drill string is rolled so that the direction of bias is the same as the desired change in direction. Drilling progress is normally achieved by hydraulic cutting action with a jet nozzle. Mechanical cutting action, when required, is provided by a downhole positive displacement mud motor.

The actual path of the pilot hole is monitored during drilling by taking periodic readings of the inclination and azimuth of the leading edge. These readings, in conjunction with measurements of the distance drilled since the last survey, are used to calculate the horizontal and vertical coordinates along the pilot hole relative to the initial entry point on the surface. In some cases, a larger diameter wash pipe may be rotated concentrically over the non-rotating drill string. This serves to prevent sticking of the non-rotating string and allows its drilling bias to be freely oriented, and also maintains the pilot hole if it becomes necessary to withdraw the steerable string. When the steerable string penetrates the surface at the exit, the pilot hole is complete.

Enlarging the pilot hole is accomplished using either prereaming passes prior to pull back or simultaneously during pull back. Prereaming tools are attached to the drill pipe at the exit point, and usually consist of a circular array of cutters and drilling fluid jets. Drilling fluid is pumped through the reamers to aid in cutting, to support the reamed hole, and to lubricate the trailing pipe. The reamers are then rotated and drawn to the drilling rig to enlarge the pilot hole. Drill pipe is added behind the reamers as they progress toward the drill rig. It is also possible to ream away from the drill rig, in which case reamers fitted into the drill string at the rig are rotated and thrust away from it.

For smaller diameter lines in soft soils, prereaming passes may be omitted and the final installation pass is undertaken upon completion of the pilot hole. In this case, the prefabricated pipeline pull section(s) is attached behind the reaming assembly instead of more drill pipe and follows the reamers to the drill rig. A swivel is utilized to connect the pull section to the leading reamers to minimize torsion transmitted to the pipeline.

Additional Observations

To maximize the advantages offered by this technique, the importance of defining the obstacle to be crossed was noted. In the case of a river or a shore approach, not only should the water's width and depth be considered, the potential for bank migration and scour should also be taken into account. It is now possible with directional drilling to have flexibility in installation not only in the horizontal plane but in the vertical plane as well. However than can only be accomplished with proper site investigation, which in general requires both surface and subsurface surveys.

A surface topographic survey should be conducted to accurately describe the working areas. Both horizontal and vertical control must be established for use in referencing hydrographic and geotechnical data. A typical survey should include overbank profiles on the centerline extending from approximately 150 feet (50 m) landward of the entry point to the length of the prefabricated pull section(s) landward of the exit point. For significant waterways, a hydrographic survey will be required to describe the bottom contours accurately, and should consist of fathometer readings along the centerline and at least 200 feet (60 m) upstream and downstream.

A subsurface survey program should include both the review of existing geological data and site specific field sampling. Existing data should be reviewed to determine the probable geologic cross section extending from the surface to either bedrock or a depth substantially below the anticipated penetration depth. This should be confirmed by geotechnical borings located approximately 50 feet (15 m) off the crossing centerline and extending to approximately 30 feet (10 m) below the deepest penetration depth. If rock is encountered, the borings should at least penetrate the rock to a depth sufficient to confirm that it is bedrock. A special point to consider is that in some locations, samples should be reviewed to determine the presence of any hazardous wastes.

In planning the overall geometry, there are normally six controlling parameters which define the location and configuration of the drilled path, namely :-

- Entry Point
- Exit Point
- Entry Angle
- Exit Angle
- Elevation
- Radius of Curvature

Entry angles should be held to between 8 degrees and 20 degrees with the horizontal, due chiefly to equipment limitations. Exit angles should be designed to allow easy breakover support, and should not be so steep that the pull section must be severely elevated in order to guide it into the drilled hole. For larger diameter lines this will generally be less than 10 degrees. Also a minimum depth of cover of 15 feet (5m) should be maintained in designing drilled profiles, as this provides a margin of safety against downhole "blowout" which can otherwise cause the drill string to seek the ground surface and force redrilling of the pilot hole.

It was pointed out in conclusion to this discussion, that although each survey may be performed by different specialized engineering consultants, it is important that the results be integrated onto a single plan and profile drawing to plan and execute the crossing. Accurate measurements in this respect are obviously essential.

Stabilization of Existing Pipeline Crossings

The problem of stabilizing existing pipeline crossings was discussed, and presentations were made in this respect by B.E. Bailey and Les Thompson. It was pointed out that recent development has yielded new possibilities to pipelines threatened with erosion problems, and that these represent alternative methods to relocation of jeopardized pipeline crossings, often with significant economic and environmental advantages. These appeared to fall into a number of categories, namely :-

Precast Block Mats
These can be machine made or form poured, creating a specific or repeatable shape. This gives more predictable hydraulic characteristics in the more critical high velocity applications. The mattresses require heavy equipment to handle and install, which can substantially increase cost in remote locations. At sites with high current velocities, precast mats are preferred because of their weight and negative buoyancy.

Grout Mat
In some cases a system of fabrics that can be inflated with concrete for pipeline stabilization is the most cost effective solution. This system does not require heavy

equipment and freight costs are less than precast. Advantages are:

- Portability (the biggest asset). The lightweight fabric form can be easily transported and local cement companies can supply injectable concrete.
- The mattress conforms well, thus requiring less earth moving.
- If access is difficult, concrete can be pumped from over 700 ft. away.

A revegetable grout mat is now available in response to the environmental community. This is a mattress with 17 to 20 percent open areas and the ability to revegetate within the open cell areas.

Modular Wall/Flexible Concrete Revetment

A modular wall is made up of individual units consisting of concrete and kiln dried sand in a specially designed bag. Each bag features 2-ply polyester with scrim reinforcement and is packed to create a brick-like consistency. The bags are pinned together forming one contiguous unit, yet remain a flexible structure. The units are good at withstanding differential settlement and freeze/thaw conditions, and will allowing for expansion and contraction of high plastic index clays.

Flexible concrete revetments are useful where vertical bank armor is required. They will accommodate wall slopes close to vertical depending on soil conditions and retention demands. Installation can normally be performed with light equipment and minimal disruption to the surrounding environment.

River Training Structure Systems

These structures (e.g. a "Palisade" system) can be effective for the control of river bank migration. When is in place, they create a zone of reduced velocity next to the eroding bank and displace higher velocities toward the center of the channel. In certain circumstances this will begin to diminish the size of the opposite sandbar, resulting in redirection of the river. With the slower water velocity in the newly established control zone, a barrier is created which protects the endangered bank. Riparian vegetation can frequently be re-established within the system's control zone. Advantages are:

- Existing terrestrial vegetation is essentially undisturbed.
- Fishery values are comparable to natural banks.
- Deposition and accretion will ultimately promote a natural ecological shoreline environment.

Effect of Dents on Pipelines

The effect of dents on the reliability of pipelines was debated. In particular there was some discussion on the likely fatigue life of pipelines with dents and gouges subjected to cyclic internal pressures. There have been studies conducted to study the effects of dents, gouges, and weld seams on pipelines under cyclic internal pressure loading. However there is still uncertainty in considering guidelines for pipeline operators in assessing the consequences of dents and gouges on the fatigue life of pipes. Stress Engineering Services presented information obtained regarding dent classification, using a survey form sent to 43 oil and gas companies. Information regarding cyclic pressure variations (amplitude and frequency) for both oil and gas pipelines was also obtained from these resources. This data supported the widely held belief that liquid line pressure variations are much more severe than gas lines pressure variations.

Mechanical damage such as dents, gouges, or a combination of both, has long been known to be a primary cause of leakage and failures in gas transmission pipelines. At present there are only very general rules governing the range of allowable defects resulting from mechanical damages. Important questions in real practice include :-

- What dents, gouges, or combinations should be treated immediately?
- Which mechanical defects are of no concern?
- What is the effect of a longitudinal or girth weld located near dents and gouges?
- Which dents or gouges may be tolerated for a specific period of time at a possibly lower operating pressure?

Although it is generally assumed that dents with gouges in weld seams would cause a substantial reduction in cyclic pressure capacity, there is still no rigorous procedure for classifying or quantifying gouge type or severity. Size relative to the pipe is also important, as a gouge which represents a scratch on the pipe surface cannot be compared to one which is 90% of the wall thickness. Recent work has indicated that, when considering defects in pipes, there is an order of descending severity as follows :-

- Defects (gouges) in a dent
- Dent in a weld seam
- Plain dent, 4% (d/D)
- Plain dent, 2% (d/D)
- Plain defect

Results presented by Joe Fowler from experiments on pipes for D/t ratios from 18 to 94 (and via theoretical finite element analysis for D/t ratios from 18 to 100) indicated that for reduction in fatigue life, the dent depth, pipe D/t ratio, and welding type were the most important factors, while the dent type and length were only of secondary importance. Categorizing gouges based on depth to wall thickness (d/t) appeared to be an effective means of classification. Their work has indicated that plain smooth dents whose diameter is less than 5% of the pipe diameter should not be a problem, assuming that the cyclic pressure loading is not extreme. Gouge depth was clearly an important factor in reducing the pipeline fatigue life - however grinding was found to be a suitable form of repair for this defect. A dent/gouge combination appeared to be particularily dangerous because of the presence of microcracks at the base of the gouge. Other interesting results were :-

- Girth welds have a greater impact on reduction in fatigue life than longitudinal welds.

- After pipe re-pressurization, the greatest dent removal occurred for the greatest initial indentations, and especially true for thinner-walled samples. This supports previous findings that dents are typically removed from thin-walled specimens while dents in thick-walled specimens are more likely to remain unchanged.

- Plain dents act as a stress concentration factor (SCF) for cyclic pressure. For small D/t pipe, this can be as high as 5. For lower D/t pipe, a maximum SCF of 3 or less results because of cyclic plasticity and shape changes of the dents. The SCF is very heavily dependent on the dent depths, but not as dependent on the dent shape. Fatigue analysis with conventional fatigue analysis procedures for dents without gouges under cyclic pressure is mostly satisfactory and conservative.

- Gouge depth has a significant impact on fatigue life. A gouge depth of 5% (with no grinding) has a fatigue life three and a half times greater than a 15% gouge depth. Gouges without dents have the longest fatigue lives, since without the process of denting, no microcracks are produced at the root of the gouge. Also the cyclic pressure variation had a significant impact on fatigue life.

- Gouge fatigue life was increased significantly when grinding was applied as a means of repair. Gouges which were ground had fatigue lives at least three times greater than non-ground counterparts. Grinding out gouges until there are no indications with dye pentrant or magnetic particle examination can greatly extend the life of a dent by a factor of 10 or more. However, it is unlikely that grinding will achieve the cyclic pressure capacity of the ungouged pipe.

- Gouges combined with dents can be very dangerous under cyclic pressure because of microcracks which form as a dent/gouge is made. These greatly accelerate the fatigue crack growth process and are the reason that the fatigue life is low. Gouges whose depth is 15% or more of the wall thickness may fail immediately. Gouges whose depth is 5-10% of the wall thickness may fail after a few thousand cycles, which can represent less than 1% of the dent fatigue life without gouges.

Effectiveness of Breakaway Fitting

The use and design of breakaway joints was debated by the group, and a presentation made in this respect by Bruce Morris of Big Inch Marine Systems. This technology began about 30 years ago when pipeline and structural designers started to consider load mitigation as a means of limiting transmitted loads. By limiting the load transmission capacity of pipelines and risers, the design load cases of anchoring systems, dynamic riser tensioners, and jacket legs and bracing became less onerous.

Simple methods of load limitation have included reduced-area bolting, and machined notches or grooves in the pipe wall itself, so that when the strength of the reduced section was exceeded, the unit failed and separation resulted. Typical shortcomings are as follows :-

- separation depends on internal and external pressure, and occurs at lower loads with higher internal pressure.

- sensitivity to bending; sections experiencing sinusoidal loading under moment application exhibit heightened sensitivity to internal pressure variations.

- separation frequently occurrs inaccurately as a result of inconsistencies in material properties, machining tolerances and finishes.

- other conditions can affect separation load such as corrosion, fatigue, and installation methods.

Purpose-made breakaway connectors were devised to address these deficiencies, starting in the late 1970's. One of the most important features was pressure compensation to eliminate sensitivity to varying internal pressures. They were also designed to provide accurate separation loads and reduced sensitivity to bending. When integrated with check valves they also offered improved environmental damage control and increased safety. Other considerations are as follows :-

Location

Locating a breakaway joint is not always easy. The further the breakaway joint is from the applied axial load, the less load is sensed by the joint. Ideally breakaway joints should therefore be placed close to the device or structure that they are to protect, although this is not always convenient. Also to facilitate retrieval and retrofit following separation, flange-by-flange installation is preferred. Another difference is that breakaway connectors, if performing as intended, are eventually returned for refurbishment and reassembly, while most conventional pipeline connector products are placed into service and are never seen again.

Pipeline loads come from many sources, and, with the exception of internal and external pressure-induced loads, the breakaway joint is incapable of differentiating between so-called normal loads such as :

- thermal expansion and contraction
- installation loads like pipe-lay tension and flange make-ups
- third party intervention like anchor drags and trawler snags

Installation Technique

The fundamental issue with regard to installation is the magnitude of axial loads applied to the breakaway joint during installation relative to the present or target separation load of the joint, as breakaway joints are indifferent to the source of an axial load. If the installation of the joint imparts a significant load, the breakaway joint could separate or, at the least, consume some portion of the predetermined separation load before the pipeline is commissioned for service. The source of these installation loads are catenary tensions for pipelay operations and flange make-ups for spool installations. Installation load retention can be accommodated by external devices such as safety rings (diver or ROV operated), but the simplest approach is to allow for a somewhat higher separation load.

External Pressure Compensation

In addition to internal pipeline pressure compensation, a means of countering external pressure is also required, since increasing water depth will increase the external pressure load on the pipeline and its associated components. External pressure compensation is now usually provided for by pressure venting of the internal cavities to the seawater environment. Where simple venting of these cavities is the most economical method, seawater exposure of internal components of the breakaway joint is not recommended due to the corrosive environment that results. Another method uses low-cracking-pressure check valves to provide pressure venting with minimal seawater ingress. This is maintained to be marginally better than direct venting of the internal chambers, although a more positive seawater ingress barrier is required in order to ensure long-term integrity of the breakaway devices.

Use of Low Friction Seals and Coatings

All breakaway joints are, by design, parting-load sensitive and, as such, require due consideration for any internal component or part-to-part interface that could offset the intended separation load. Friction between mating parts represents the greatest error-inducing influence to the breakaway joint's overall design. As separation loads increase, the error in separation load due to internal friction becomes less and less significant. It is now possible to reduce the error due to internal friction to within 5 -10 % of the tolerance range of the units separation.

Check Valves

Check valves are commonly used with breakaway joints to satisfy safety, operational, and environmental concerns. Both normally-directed and reverse-directed flapper-type valves are used to close off the separated ends of a breakaway joint to control liquid spills, prevent pipeline flooding, and minimize gas explosion hazard. When reverse oriented valves are utilized, a special stinger tube is affixed to one-half of the joint which extends through the bore of the valve holding the flapper up and out of the pipeline flow. When check valves are used, the pipeline operator should consider additional valves on either end of the breakaway joint spool to facilitate check valve retrieval without flooding pipeline (since the flooded line cannot be readily pigged).

In conclusion it was noted that although early experiences with such devices exhibited sensitivities and problems, breakaway joints can now claim to be reasonably trouble-free devices that offer a means of limiting design loads and benefitting from the resulting cost reductions. With some design modifications, breakaway joints can be designed now to tolerate special case applications, such as deep water or cyclic pressures, but the end users should recognize that enhancements in design will certainly be accompanied by additional costs. It should also be recognized that, unlike other connections, breakaway joints are designed to come apart, and the pipeline operator should develop a contingency plan for recovery from a joint separation. This could include a standby replacement breakaway joint or, at least, spool components to temporarily recommission the pipeline while the joint is being refurbished.

Protection Against Snagging

The problem of snagging of nets, trawls, and other gear on unseen obstructions on the sea floor came up for discussion. This is a perennial source of friction between the oil and gas industry and other marine activity. The State of Louisiana and the National Oceanic and Atmospheric Administration (NOAA) each dispense funds collected from the offshore oil and gas industry to fishermen whose claims are creditable. NOAA publishes the locations of these sites in weekly notices. Once a hang location has been identified, no further compensation will be given to fishermen at this location.

A recent atlas for the northern Gulf of Mexico of sites of such "hangs" reported by shrimpers included approximately 7,500 locations where shrimpers have lost or damaged gear in water depths up to 300 feet. Of the reported locations, fewer than one (1) percent were attributed to pipelines; three (3) percent were thought to be caused by natural formations; four (4) percent were attributed to lost cargoes, ship and plane wrecks, anchors, and a variety of other human-made debris, exclusive of pipelines; and eighty-nine (89) percent had no identified cause. These figures give no indication of the frequency with which pipelines are snagged.

Burial Requirements

Pipeline burial reduces the chance of interaction with vessels. Consequently, MMS requires that pipelines originating on the OCS be placed at least 3 feet beneath the bottom in water depths less than 200 feet. Nevertheless, the Regional Supervisor, at his discretion, may require burial of any pipeline if he determines that the pipeline may constitute a hazard. Likewise pipeline valves, taps, and tie-ins must be installed with at least 3 feet of cover unless the Regional Supervisor determines that such items present no hazard to trawling or other operations.

Pipeline valve assemblies are clearly a particular hazard in this respect, and burying them has so far been the main way of reducing their interaction with marine activities. In shallow water depths this will remain a viable option for producers and operators to protect their pipeline systems, but for deeper water depths, new methods of protection are desirable. Burial still remains an option for deeper waters (greater than 300 feet), but the cost increases significantly because of limitations with present jetting operations. There are very few construction vessels operating in the Gulf of Mexico today that can bury valve assemblies and the adjacent pipe at these depths, and the alternative is to use diver-intensive hand-jetting.

Use of Valve Guards

Alternative protective devices (i.e. valve guards, concrete mats, etc.) may be used to cover an obstruction in lieu of burial, if approved by the Regional Supervisor prior to installation. Of these, the most direct solution is to employ valve guards to protect pipeline valve assemblies. Typical configurations have utilized small diameter pipe to form a lightweight open space-frame, which allows the guard to be installed by a dive boat. Such a design has the disadvantage that without a plate or grating covering the guard, objects pulled across the guard could become lodged in the bracing.

Eric Romero and Britt Schmidt gave a presentation regarding a new design of subsea valve guard used for installation in deep water, where burial would have been very costly because of the water depth and the size of the valve assembly. Important considerations addressed in design were as follows :-

- Design life to coincide with the design life of the pipeline
- Two foot minimum clearance between the interior side of the guard framing and the pipeline and valves.
- Exterior of guard frame to be plated to minimize the possibility of hangs from trawling and construction operations as previously experienced with open-framed valve guards.

- The sides of the guard to be sloped at 45^0 to minimize the effects of accidental loads caused by objects dragged along the sea floor or dropped from boats or barges.

- Provision for future tie-ins to the subsea assembly without removal of the valve guard.

The size and configuration of the guard were determined by the clearance and slope requirements. Design loadings included dead load, live loads, environmental loads and installation loads. In-place vertical loads included the in-water weight of the guard and a concentrated design load of 3,000 pounds to approximate the weight of a supply boat anchor. In-place horizontal loads included storm generated currents and accidental loadings due to trawling operations. Installation loads included the lifting and lowering operation from a single point with slings attached to the guard's four lifting eyes. Corrosion protection was provided by a coal tar epoxy coating system and supplemented with sacrificial anodes. Foundation support was provided by mud mats, shear skirts and screw anchors. Scour mitigation was provided by the skirt penetration and the placement of sandicement bags around the perimeter of the guard.

The initial design concept was to minimize the weight of the guard to reduce fabrication cost and allow the pipeline lay barge to place the guard on bottom during the pipelay operations. This would allow final positioning of the guard with a dive vessel. Additional features of the valve guard included the use of a removable hatch section which allowed for future tie-ins without removal of the entire guard. Also the grating was placed in strategic locations to give acceptable water flow characteristics for offshore installation. This allows sufficient water flow through the guard to compensate for surges of the construction vessel and easier lowering operations.

The use of square and rectangular tubular for structural members allowed easier fabrication. Holes were placed in the tubing to accomodate the bottom pressures that the valve guard would experience. The hatches could open 180^0 for a diver to access the valve assembly, and to provide additional safeguards against inadvertent closures of the hatch on the diver's hose on entering the guard. Specifying low profile "hull" type anodes also minimized the possibility of hangs from trawling and construction operations.

Overall it was agreed that it is not possible to design a zero risk protection system for subsea valve assemblies. However special precautions can be taken in zones of high traffic and high pipeline density. Particularily for deep water locations, the use of valve guards is an innovative approach in solving the problems associated with subsea valve protection. Design requirements will vary from project to project based on life expectancy, location, and water depth.

Subsea Pigging and Pig Retrieval

A general overview on the problems of pigging offshore and in deep water was given by Glen Lochte. This covered the problems of wear, pig movement through the pipe, pigging speed, and materials of construction. Locating suitable pig entry points and disposing properly of pigged material were additional requirements that were often neglected by operators. It was pointed out that for optimum results, generous pipe radii should be provided, pipe should be smooth with no branches or valves, pig travel should be at normal flow velocity and in the normal direction of flow. Long distances can result in greatly extended pigging times. Assuming an average rate of travel of 4 mph., a 60 mile round trip will take 15 hours, with consequent economic effect on product sales. Typically usage at a frequency of 1 pig per week will result in about 9% downtime.

For subsea launcher and retriever situations, additional extensive surface support is necessary. Equipment costs are typically of the order of $0.5 million excluding riser and umbilical. Operation times require at least 3 days including mobilization and demobilization, and inspection cleaning times can be increased by orders of magnitude. Pigging fluid costs can also be significant.

It was pointed out in conclusion that virtually all offshore pigging operations involve much higher costs than on land. The cost implications of a stuck pig or of verifying intelligent pig anomalies can be severe. It is also now technically feasible to utilize a subsea pig receiver, although this has yet to find extensive application in the field.

WORKING GROUP REPORT 4

"REPAIR CONSIDERATIONS"

Chuck Hebert, McDermott Inc.
Jim Cordner, BP Exploration

Introduction

All underwater pipelines fall into three categories:- Marsh or Coastal, Shallow Water, and Deepwater. Marsh or Coastal pipelines are those that are constructed in coastal areas, or within the coast line and do not go out into open waters. These are easily accessible and there are usually many repair options when damaged. Shallow Water pipelines are installed in open waters from a coastline out to a maximum water depth of 1,000 feet. These are not as accessible as pipelines in marsh areas. Although they can be repaired by conventional means, there are fewer options for repair techniques. Deepwater pipelines are defined as those installed in water depths in excess of 1,000 feet, or (depending on who is making the designation) as much as 1,200 feet. In reality the primary distinction between shallow and deepwater is the depth beyond which pipelines can no longer be accessed by diving. This is now generally accepted as 1,000 to 1,200 feet, although there are diving systems that can go deeper.

Procedural Issues

Frank Patton with the MMS reviewed some of the procedures that should be followed when a pipeline leak occurs. The MMS requests that they be notified whenever a leak is encountered. They will want to know the repair procedures including flowline evacuation procedures. MMS realizes that there are times that the line can not be evacuated, and they then ask that pollution recovery equipment be on site. They also realize that sometimes it is not obvious whose leak it is and are willing to work with a group to identify the problem. The issue is that involvement of the MMS is important, as soon as a problem arises. They are part of the solution and not the problem.

Jim O'Brien discussed some of the problems of pollution and the considerations to be taken in an actual spill. These include :-

- Casualty Damage Control
- Public Affairs, Public Relations
- Agency Interface
- Information Flow, Transfer
- Strategy Development
- "The" Oil Spill

It was pointed out that the Coast Guard, by law, shall direct oil cleanup. The state agency has responsibility for cleanup as does the owner of the pipeline. When there is a disagreement, the Coast Guard has the final authority. A great deal of progress has been made for pre-approvals for various clean-up activities. Local Coast Guard authorities can approve burning if applicable. Clean Gulf Associates has dispersants available on 24 hour notice. It is important that, before any spill, supervisory personnel should know the produced fluids characteristics, whether or not it emulsifies, if it has light ends, and what the specific gravity and evaporation characteristics are. Operators must have plans in place, not just for the large spill, but also for 5, 10 and 50 barrel size spills.

Damage Assessment

A discussion took place on the subject matter of damage assessment. This was based on the assumption that damage resulted in a leak and that the assessment was to determine the cause of leak. Phil German with Intec Engineering made a presentation, in the course of which it was pointed out that leak detection has limits on accuracy, and therefore, there is limited value for monitoring for a leak. This is particularly true in a gas system with great amounts of product in the line. Sonic wave inspection is one method of damage assessment, but is also better suited for a liquid systems. However, due to background noise, it has limited capabilities for locating small holes in the line.

It was agreed that the most acceptable method of internal inspection is acoustic, magnetic, ultrasonic, or geo- inspection, used in conjunction with a pig if the line is capable of passing a pig. If a line is mechanically damaged, however, it is unlikely that one would want to introduce a pig into the system. External systems, such as ROV, Fish, Diver or Surface observations can be used very effectively to locate external deformities if conditions permit. The conclusion was that there is no one technique that can work in all situations, bearing in mind that product type, location (deep water, shallow, buried) and distance of line can all affect the method to be used.

Damage Survey and Concerns

Before a pipeline can be repaired, one of the most difficult things can be to locate its precise position. The relative difficulty of locating the pipeline is affected by factors such as the cause of the damage, the water depth, the product (oil or gas), and whether the pipeline is buried or exposed, flowing, flooded. Some discussion took place about the relative merits of different survey techniques, with the prevalent survey systems being GPS and DGPS.

In reality one of the most neglected essential elements for rapid response is information possessed by the owner. This can come initially from the operator who should have a description of the pipeline (owner or owners, size, product, location) and the approximate location of the damage or break. Sometimes a boat or helicopter can provide a Loran or GPS position on gas bubbles or an oil slick. The established survey companies are often able to supplement this with a GIS database information package consisting of computer disks and maps generated by a search of their existing extensive database. On offshore vessels this can sometimes be incorporated into a dynamic graphics software system.

Ron Bucher of John Chance & Assoc. described some of the latest survey equipment developments. They use the Starfix DGPS satellite positioning system, which is a satellite-based system, as originally developed by the U.S. Department of Defense, but used in a differential mode to compensate for the Department of Defense's degradation of the original positioning signal, as otherwise errors of 50 to 60 m. are not uncommon. In a differential system, one or more GPS receivers are placed at known locations called Reference or Base stations. These sites are precisely located and the difference between that location and the position solution from the GPS is a measure of the GPS error, which can then be used as a correction in the other receivers.

In some cases locating the pipeline damage is easy. For example, with a broken gas pipeline, it may simply be a matter of setting up the dive vessel near a flow of bubbles. In other cases it can be difficult to locate a pipeline in the damaged area even if reliable as-built information is available. Incidents have occurred where pipelines were displaced by as much as 1500 feet by an anchor, hurricane or mudslide; or in other cases were buried ten feet or more. In such instances it is prudent to run a wide-area detailed side scan and magnetometer survey to locate the break and possibly determine the cause.

Side-Scan Sonar Systems

Side-Scan sonar systems (like the EG&G SMS-960 Seafloor Mapping System or similar) typically consist of a master unit, digital tape deck, towfish and a tow cable system. The towfish is a hydrodynamically stable towed body that contains the transducers and electronics necessary to generate the sonar signal and receive its echoes. Some systems also use a microprocessor to apply automatic spatial corrections for slant range and speed such that the hard copy record is a true plan view, and the size, shape, and location of any seafloor material or object can be directly measured. 25 meter scale markers can be superimposed over the record to permit accurately scaled measurements.

The hard copy data acquired in the field, or played back in the lab, can be put together into a mosaic display to form an acoustic picture of the seafloor. The final product, similar to an aerial photograph, will be an accurate representation, to scale, of features that are present in the area of interest. These mosaics are helpful when we are investigating man-made damage, like anchor drags or jack-up rigs.

Magnetometers

Sidescan sonar cannot always distinguish pipelines that are buried, in which case a magnetometer is useful to detect ferrous objects such as pipelines. A survey vessel must usually run reciprocal lines across the search area, recording position fixes of the GPS antenna when the magnetometer crosses the pipeline. The reciprocal position fixes are averaged to obtain an accurate pipeline position.

Shallow Water Repairs

Pipeline repair in shallow water has more options because the pipe can be reached by divers, can be lifted to the surface or dredged to make the repair. For instance, cutting-out a damaged section of pipe and installing a pup piece, might be the preferred approach on-land, but for an underwater pipeline the cost of pick-up and repair would normally be prohibitive. One method is the use of a portable caisson (or coffer dam) for shallow water repair, and Mr. Danny Hughes described a system that can be deployed in 20 ft. of water on large diameter pipe or 30 ft. of water for smaller diameters.

With a caisson, the engineer has the latitude to choose any repair operation he/she would normally utilize on land. The only restriction is that the operation needs to fit in the space provided. The main function of a caisson is to provide safe and adequate access to underwater pipelines without damaging or over-stressing them. The great advantage is that dry welding and inspection etc. can be carried out by non-divers (although personnel may need confined space training). A subsidiary benefit is that on welded procedures, a Low Hydrogen Procedure will suffice. Inspection can often be done by Company or Operator personnel, including X-Ray, and ultrasonic testing.

Access to the damaged area can be by barge or marsh buggy depending on conditions. The caisson is lowered, and, if necessary, piles can be used to stabilize the system. The caisson is excavated by ballasting the ballast chambers. The pipe is evacuated by pigging with nitrogen or such other gas as may be applicable. The buried pipe must be stripped back to be accessed and measured for the mandrels. Ventilation systems are used in the evacuated caisson as a safety measure. Workers can enter the caisson and perform the work. The system is then flooded and the caisson is removed.

Repair activities that can be effectively carried out by this procedure include :-

- Damage repair utilizing mechanical or welded procedures
- Hot tap installations utilizing mechanical devices
- Hot tap installations utilizing welded procedures
- Installation, removal or replacement of valves
- Installation or removal of flanges
- Replacing or changing directionally drilled crossings
- Re-routing pipeline systems

The primary advantages are :-

- Allows access to all personnel, not just divers.
- Allows first-hand inspection, as well as generally accepted methods of dry inspection, for pipeline repairs, modifications, etc.
- Allows a standard, dry welding procedure.

- Allows work to take place on a pipeline in-place, with a minimum of disturbance, without stressing the subject pipeline.
- Minimizes associated damage to the surrounding environment.
- Enables a fast turn-around for repairs and modifications.

The main disadvantages are :-

- Restricted use as to water depth and location.
- More safety-sensitive during welded procedures as compared to underwater mechanical procedures.

Surface Diving

A discussion of safety, and the relative ease and difficulty of pipeline repair by surface diving, was led by Mr. Lanny Falgut. Safety considerations included :-

- Is the line under pressure?
- Possibility of chemical Burns
- Pipeline rupture
- Suction by pipeline
- Back strain
- Water blaster safety
- Can the diving vessel be placed upwind?
- During pressure test, is the diver away from the clamps?

Simple repairs can be done with a split sleeve clamp. Depending on the conditions, a live boat, barge, or spread moored vessel can be used. Difficult repairs may involve a spool piece. In this case a forging tool is used to make up the flange connections onto clean pipe. An annulus test assures that the forging is good. The spool piece is lowered into place in a flexed condition. After one end is made up loosely, the second is made up, also loosely. Once both ends are fitted, the ends are torqued, and the flexible joint then tightened. Sand bagging is then performed if required, and pressure testing performed.

Using Divers for Repair at Depth

For many problems there is no substitute for using divers to gain manned access for repair. Whenever intensive bottom time is required, saturation diving is preferred, and Mr. Jim Macklin of Cal-Dive International led a discussion on this topic. Saturation diving is a procedure whereby a diver is continuously subjected to an ambient pressure greater than atmospheric so that his body issues and blood become saturated with the inert elements of the breathing gas. Once his tissues become saturated, he can remain within at that depth for an unlimited time without incurring additional decompression obligation.

Saturation diving has the advantage of delaying decompression time for the diver until after the project. It is used any time the depth and work time dictate that extensive decompression time is required, and is effectively required for depths beyond 300 ft.. Saturation diving has proven to be effective for pipeline repair by divers in water from as shallow as 150 ft. to present operational limits of approximately 1200 ft., although there have been experimental dives to 1700 ft. utilizing exotic hydrogen trimixes. Response time for pipeline repair is also a major advantage, as a crew can be assembled and a saturation ready vessel away from the dock in as little as eight hours.

Damages to pipelines requiring split sleeves, spool piece repairs, end connectors of any type or hyperbaric welds can be effected efficiently in saturation. A diver's typical lock-out time, that is the amount of time physically spent out of the bell, ranges from four to five hours, with the only real constraint being fatigue and safety. Work can effectively be continuous, as the diver can then exchange with his partner in the bell, who can continue for a similar period of time. In deeper depths (beyond 500 ft.) these times may be foreshortened to allow for recovery and redeployment of the bell to the deck and transfer of fresh divers to the work site.

Effect of Sea State and Weather Conditions

One traditional concern of diving has been its perceived vulnerability to the sea state and bad weather conditions. Modern equipment in the Gulf of Mexico is now in reality only marginally affected by weather conditions. Once on location with a good anchor set positioning the dive boat into the prevailing wind and seas, there is no difficulty in launching and recovering in 6 ft. to 8 ft. seas. The use of moon pools and a cursor system (which extends below the vessel hull and captures the bell) now allows safe stable recovery in sea conditions beyond 8 ft.. This is improved even further with the latest diving platform vessels, which can continually adjust bow heading to achieve a constant sea-friendly operating station. However moving or setting anchors in these conditions is still not recommended.

Diverless Pipeline Repair Systems

Several projects are currently studyinging the best means to repair lines beyond accepted diving depth limitations. The Deepstar Group and the Oman-India Group are both evaluating new connector systems and modifications to existing systems to permit repairs utilizing Remote Operated Vehicles (ROV's), although there seems so far to be no generally accepted and proven connection system for diverless subsea pipeline repairs.

Mr. Rick Morgan discussed a diverless repair system, funded by Norwegian operators, for which an offshore, in-water test was shortly planned for a 16" pipe. The system is not designed to tolerate much misalignment, and is built by Hydratight to be installed with Statoil's H frame system. The system strength, shear, moment, internal pressure and external pressure capabilities all exceed the pipe capacities.

Diverless pipeline repair systems should have the advantage of being good for both deep and shallow water repairs. Some of the relevant issues were discussed by Mr. Cliff Chamblee, who described such a system, using a spool piece repair, manufactured by Sonsub. The depth limitation is ROV and surface winch dependent, as it is designed without any pressure-sensitive components in the subsea hardware. The system can tolerate a +/- 7^0 alignment, and uses a telescoping feature to make up ends. It can use Sonsub's X-lock connector, but can also use other manufacturers' connection systems. The process lifts the pipe off the seafloor, cuts the pipe either with abrasive wire or hydraulic slurry, aligns the pipe after the cut, measures the repair length, winches the repair piece down, actuates the pipe connectors, lowers the pipe back to the seafloor, and then locks the telescope piece into place.

Pipeline cutting is preferably done with grit entrained water, although other methods are possible including reciprocating blades, cut-off wheels of various types and rotating milling cutters. The major advantage of grit cutting is the absence of any intrusive device such as blades or cutting wheels which can be subject to jamming or breakage should the pipe "close" or twist during the cutting operation.

Pipe end preparation is also required whatever method of mechanical connector is used. This normally consists of the removal of any protruding horizontal weld seam and the machining of a set of shallow parallel grooves around the circumference of the pipe in the area where the sealing/gripping ring is to locate, and can also be done remotely. Particular advantages of such a pipe repair system are claimed to include lightweight, modular design, deployable from a typical DSV or similar vessel, with tooling and intervention hardware to be "bottom founded". In addition specialized personnel or training would not be required to operate the repair system, as all tasks should fall within the skill capabilities of available ROV technicians.

Offshore trials have recently been conducted to ascertain the capabilities of such Advanced Remotely Operated Work System (AROWS) class ROV's to carry out deep water pipeline repair. These have now been used in the simulated replacement of a damaged section of pipeline, by cutting and removing a 6 m. section of pipeline and to maneuver and align the cut ends of the pipe, prepare the pipe ends to accept a mechanical connector and position a new section of pipeline plus connections to effect a repair. Successful tests have been conducted on a section of 26 inch pipeline in 300 m. of water off southern Italy.

Other Problems with Repair by ROV,s

A repair consideration that can often prove difficult, is pipeline elevation before repair, to lift the damaged section off the seabed to provide access for the repair equipment. The usual method of elevation utilizes either lift wires from the surface support vessel or diver deployed and operated "H" frames. Lift wires from the surface, while acceptable from an ROV intervention point of view, require calm weather conditions and vessel stability. The "H" frame offers the major advantage of being bottom founded, thus not affected by surface weather conditions or vessel movement. However, "H" frames for pipe over 24 inch diameter are large and cumbersome units, difficult to deploy and position.

Another alternative is to use water inflatable jacking bags. There offer the strong advantage of needing very little space under the pipeline for installation, so that access for the lifting bags can be obtained by dredging. Once in position they can be inflated sequentially to give the required lift and catenary. They do have the major disadvantage of providing little in the way of lateral stability with no capability of controlling lateral movement of the pipeline. However this can be provided with a pipeline trestle, consisting of a double lift bag assembly to elevate a lifting beam carrying a traversing trolley. The pipe trestle can then be readily pulled under the elevated pipeline via an ROV operated subsea winch.

Other Repair Techniques

Mr. Glen Lochte talked about repair techniques, and noted that the usual options, requiring diver intervention, are :-

- Hard spool replacement, good for damage along a pipe section possibly crushed by a jack-up or dragged anchor, and
- Clamps over exterior, good for areas with pin hole corrosion leaks.

In order to improve their ability to respond to emergency failures/repair capabilities, a number of operating companies of gas transmission lines agreed some time ago that they should jointly improve their ability to respond to emergency failures of their lines. Based on an inventory of mechanical repair equipment owned cooperatively by a group of pipeline companies, the Response to Underwater Pipeline Emergencies system was initiated. The use of mechanical connectors was selected over weld-type repairs due to the potential time savings of the procedures. Also mechanical connectors can be stored for an indefinite time period, and their installation can be performed by virtually any diving contractor in a cost-effective manner. Over 20 companies, (some international) now participate, and the annual operating budget is now approximately $200,000.

The program currently has sufficient connectors to make two spool-piece repairs for most pipe sizes. Additionally, two repair clamps are maintained for most pipe sizes. Repair couplings can be shipped within 24 hours. Subsea handling frames were also kept in stock, but based on recent improvements in subsea handling equipment and availability (and to reduce operating and maintenance costs) these have now been disposed of. Out of 8 to 10 call-ups (mobilization of tools) last year, all were clamps (no repair spools), of which only 6 to 8 were used and the rest returned. When a repair item is used, the company is required to pay for the replacement back to inventory. A participant's cost involves buying into the inventory, followed by an annual cost for upkeep and taxes on the inventory.

Some interesting trends have become evident with time. For example, during the first 6 to 7 years of operation, numerous connectors and some clamps were used. However, during the past 3 to 4 years, virtually all inventory withdrawn has been repair clamps. This is believed to be because initially there was a high level of construction activity in the Gulf of Mexico. This inevitably resulted in some mechanical damage to pipelines by work barges, etc., thereby necessitating spool piece repairs (use of connectors). After the downturn in production in 1986, construction activity decreased. Reduced capacity (velocity) in the gas lines and settling of liquids also caused isolated corrosion. Subsequent demand was therefore primarily for repair clamps.

Mechanical Connectors

Mechanical connectors have now generally become the most widely accepted means of repairing subsea pipelines, although for years there was no available inventory of connectors for emergency repairs. This has now changed, and inventories are available for sizes up to 24 inch. Larger designs are available but are rarely in stock. Practically all vendors have concepts for diverless systems, although most are still in development plans due to shortage of funding. Mr. Lee Avery reviewed some of the shallow water connection systems available.

In addition to the inventory held by the RUPE (Response to Underwater Pipeline Emergencies) group described previously, two other connector companies, namely American Oilfield Divers' Big Inch Marine System (BIMS) and Oceaneering's Pipeline Repair System (PRS), have now established independent inventories of their appropriate connector systems (Flexiforge and Smart Flange respectively). Both companies offer a repair alternative to members of the RUPE consortium, and to other oil and gas companies as well.

Overview of Other Connector Options

Pipeline Repair System's Smart Flange connector relies on the actuation of elastomeric seals and gripping slips by the tightening of a series of flange bolts. The same tightening sequence was also designed to effect tie-in of the connector to the subsea mating flange. The connector incorporates a seal limiting ring to prevent seal extrusion and a load limiting ring to prevent possible damage to the pipe from over-tightening of the slips. The integrity of the connection is verified by measuring the gap between the end flange of the connector and the mating subsea flange. An annulus test port can be provided on select models. An inventory of Smart Flanges has now been established for the 2" through 24" size ranges, and the manufacturer reports over 800 sales of this particular system.

The Flexiforge pipeline connection system represents a different approach, and relies on the use of a hydraulically actuated mechanical rolling tool which is inserted inside the end of the pipeline. Activation of a tapered cone in the Flexiforge tool causes the mechanical rollers to expand radially until they forge the pipeline to create a bond to the interior of the connector, forming a series of metal to metal seals and structural attachment bands between the connector and the pipe. The integrity of the forging is verified by measuring the actual forging tool cone travel and comparing this to prescribed computer-generated predictions. In addition a low pressure air annulus test can be conducted, to check the pressure integrity of the metal seal rings. Since these seal rings also constitute the structural attachment to the pipe, a successful seal test simultaneously verifies that the connector is bonded to the pipe O.D. These connectors are now held in inventory for the 6" through 24" size range, of which over 300 worldwide sales have been reported. Some components are available in sizes 4" through 24", such as swivel ring flanges and ball flange misalignment connectors.

As a result there are now three primary connector options available for subsea pipeline repairs in the Gulf of Mexico in size ranges up to 24" diameter. The RUPE Group's HydroCouples, PRS' Smart Flange and Big Inchs Flexiforge End Connector all offer an extensive track record of successful installations. However it should be noted that options still remain very limited for large diameters, as only the RUPE Group stocks 30" and 36" connectors. Neither PRS nor Big Inch have chosen to build inventory connectors in these large diameters due to the relative high cost of initial manufacture and the reduced damage incidence rate for these sizes. Without some industry funding it is unlikely that any connector company will self-fund the stocking of connectors larger than 24" in the near future. Non-RUPE members have no available repair option for 30" and 36" main lines.

Flexible Pipe Repair

Special problems are presented by the repair of flexible pipelines, and Joe Killeen with Mobil gave a presentation of a recent successful operation in this respect. A flexible pipeline owned by Oryx Energy Corporation was snagged by an anchor near a platform in about 250 feet of water. This was part of the development of four subsea Mississippi Canyon wells in water depths ranging from 1355 ft. to 2103 ft., which first came on line in 1993. Flexible flowlines and umbilical bundles from each well were tied back to a shallow water platform, representing the longest and deepest flexible pipe installation in the Gulf of Mexico to date.

In August 1993, less than two weeks after initial production start-up, a lay barge working in the area snagged the flowline with an anchor. The anchor had been inadvertently dropped due to "premature disengagement", and during retrieval the winch operator noted extreme dragging with additional tension. Upon inspection by a surface diver, it was determined that the flexible pipe had been caught in an anchor fluke and winched to within 90 feet of surface, or nearly 285 feet above the seabed. The pipe and umbilical were then lowered back to the seabed and the winch line was cut. A preliminary diving inspection revealed that the 400 foot excess slack loop near the platform had been "pulled out". The pipe had suffered external shield damage and armour wire exposure with possible kinking, but no ruptures or leaks. No damage was done to the umbilical. After consulting the MMS, the pipe was pressure tested with nitrogen satisfactorily and returned to service while remedial action was planned.

Review of the diving video suggested that the pipe life may have been jeopardized even though it had been pressure tested and returned to service. The decision was then made by Oryx to recover and replace the damaged section of pipe. To aid in planning the recovery and repair operation, an ROV survey was performed to provide more detailed inspection of the pipe and umbilical, and to obtain accurate positioning coordinates of the pipe on the seabed. This proved very beneficial in the procedural planning of the recovery operation. The decision was made to conduct the repair operation during the third mobilization of the lay vessel. Since Oryx had a spare end fitting and a 2500 ft. section of flexible pipe in stock, the repair operation included replacement of a 2500 ft. section of flexible pipe which contained the damaged area.

The general procedure was as follows. The well was shut-in and pressure was bled off the flowline. The line was filled with nitrogen to minimize any flammability concerns during line cutting and end fitting installation. Divers then installed a bridle with soft slings on the pipe, to pick-up and relocate the bundle, and to undo loops in the damaged area. This process reduced the chance of kinking or flooding the pipe during recovery operations. Divers then installed a bending shoe under the flowline/umbilical. The bundle was pulled out of the j-tube (reversing pull-in procedure) and reeled up separately to the anchor-damaged section, while the ROV monitored the recovery. After inspection of the pipe and umbilical, the pipe was nitrogen pressure tested, and the well returned to production.

This repair job was originally planned to immediately follow the installation of the third flowline. However, problems encountered on the subsea well end meant that the rig was not ready to commence keelhaul operations when the lay barge arrived. To prevent excessive standby time, the lay barge performed the repair work while the rig remedied their problem, thus minimizing laybarge and rig standby time.

The operation has demonstrated that it is possible to effect a carefully planned and executed flexible pipe repair. The relative durability of such flexible pipe has also been demonstrated by the inadvertent anchor snag of this flowline.

Panel Discussion - Deep Water Repairs

A panel discussion took place regarding the overall issues concerning deep water repairs, led by J. Wilkens of McDermott, Gary Harrison of Hudson, Cliff Chamblee of SonSub and Mike Garrett of Amoco Pipeline. It was noted that failures can be classified into two types - during lay, and during operations. Typically, the installation contractor is required to have a repair method during installation. One repair option is to replace a pipeline, particularly a relatively short line, if the cost is less than a repair scenario. During installation, the option is typically to pick up the broken ends and make repairs above the water. This may or may not be an option on existing lines.

At the present time there are approximately 30 lines worldwide in over 1200 ft. of water. Since failures have so far been rare, it is hard to see how anyone can fund much development work for deep water repair. One issue is how to get the oil out of the line, particularly if you do not intend to fix it. One option is to pick up the line and pig it. However, if that is done, then the repair should be performed. If there is a leak in a gas pipeline, and water enters the system, how do you get rid of hydrates that may form? There are not many acceptable solutions, and it can be concluded that there are not many repair options for deepwater pipelines.

Panel Discussion - Project Management and Planning

The particular problems of project management and planning was debated in a panel discussion with Scott Preston of BP Exploration, Rob Von Tungle of MPC, Gary Voight of McDermott, and Danny Schwartz of American Oil field Divers. In response to the general question "What is the thought process for planning an emergency repair to a pipeline?", the replies from the panel were as follows :-

BP

"While we do a very good effort to design the installation of the pipeline, we tend to simplify the repair of the line once field operations begin. Operation companies stress a quick repair. Typically the operator will go back to the original installation contractor, hoping that they have personnel and equipment available. The first 48 hours of interaction are critical to creating a plan. Once the plan is started, it is important to concentrate on following the plan, and not to let other ideas start to weaken the effort."

MPC

"One good way to prevent damage is by design on the front end. Examples are fitting a splashtron on the riser, and burying pipe under a crane area. An engineering firm can assist with welding procedures, inspection, etc., and can also serve as the liaison between the installation contractor and the operator."

McDermott

"The most successful repair jobs concentrate on safety and method etc., and are not concerned with contract issues. Historically repair jobs are a true partnering relationship."

American Oilfield Divers

"Procedures are important. Boiler plate plans in shallow water can be boiler plated, but they must also have contacts for crossed lines etc.. Common sense dictates that you have repair hardware, plans, and contingencies, etc.. Make sure you know where the equipment and materials are."

Final General Comments

It was agreed that procedures are very dependent on the type of working platform used - whether it is a DP Boat, spread barge, etc. - as this all affects the procedure. It is wise insurance to have repair connectors available on the shelf. Plans in place are difficult because you cannot necessarily anticipate the problems. As an example BP's MC 109 repair involved a breakaway joint. It was not obvious if the repair would require replacement of the breakaway or an insitu repair. Planning was performed, but not preplanning.

In the absence of a plan, one can have some guidelines to assist in making plans once the problem is identified. One thing often left out of the plan is what to do with the product. How is it displaced and where will it be stored ? Is this equipment available on the market ? Plans should include :-

- Who carries repair equipment in these sizes, what is the availability and lead time for fabrication, etc.
- Vessels that could be used, and phone numbers.
- Contacts for tie-in owners.

On the front end, designs should avoid unusual sizes and pressure ratings. Almost all shelf equipment is ANSI 600. Assembling the appropriate field personnel, superintendants, and divers etc. all in the same room helps to get a good plan. An additional suggestion was to practice a damage scenario, by calling in the personnel that would be called in the actual situation, and then to create the scenario.

WORKING GROUP REPORT 5

"RESPONSE TO ABNORMAL SITUATIONS"

John Bomba, Kvaerner/R.J. Brown
Dave Rechenthin, Clean Gulf Associates

Introduction

This session began with a general introduction, followed by some presentations on special topics concerned with response to abnormal situations, and an open discussion and review of audience feelings on the topics. In each case a substantial amount of audience participation was possible, including question and answer periods where desired.

The problem of location of pipelines, both on land and at river crossings, was addressed. Pipeline locating equipment has been available for some time, but there have been major improvements in the technology. They appear to be particularly useful for emergency call-out, and have been used recently for instance at the Gila River (Santa Fe Pipelines), at the Missouri River and at the San Jacinto River (Explorer Pipeline).

Pipe Location Techniques

Present day locators often utilize multi-frequency techniques due to the variety of services and the complexity of underground networks, and Mr. Ernest Casey spoke on the subject. Common frequencies used are 60 Hz., 1.0 kHz., 4.0 kHz., 10 kHz. and 35 kHz. (the latter designed for use with underground cables). In the event that it is possible to couple directly to a service, this method will provide the most accurate results. Where it is not possible to tie into a service, induction methods can be utilized using either 4.0 kHz. or 10 kHz.

The transmitter is equipped with output sockets for direct connection, and also an internal antenna for inducing a signal to a service. The transmitter generates an electro-magnetic signal of approximately 30 vac at 1 amp and some units are equipped with boost facilities of 5 amps. The receiver is equipped with an antenna which utilizes induction coils mounted either in a horizontal plane (Co-Sine) which provides a maximum field when directly over an energized service, or vertical which indicates a null (Sine) when directly over a service. Most present-day receivers are fitted with analog and digital outputs, also a speaker, and RS232 output.

Having located a service it is often desirable to ascertain the depth of cover. This may be achieved by various techniques. One method is that of triangulation which is carried out by locating the service at maximum signal strength and by use of the Co-Sine method and walking perpendicular to the service until 50% of the original signal strength remains. By marking the two points and measuring the distance between, this can often be related to the distance from the ground to the center of the service.

Other methods utilize twin horizontal antennae which, by comparison of signal levels, provide a depth of burial function. Both methods can be accurate if calibration is carried out against a known depth and if there are no extraneous signals which can cause erroneous readings - therefore subsequent erroneous depth information. The 60

Hz. selection on the receiving unit provides good location of power cables and most operational pipelines. Normally, pipelines are cathodically protected by a low dc voltage. The rectified current at 120 Hz. can be detected, being a direct harmonic of 60 Hz. Depth of cover measurement using this method is not advised unless the work area is away from built-up areas or powerlines.

River Crossing Surveys

Purpose-made systems have also been constructed for river crossing surveys, based on electromagnetic technology, which have the ability to locate pipelines at river crossing locations, determine pipe depth, water depth and geographical position at the same plane. Application involves laying a cable across the river section to form a closed loop. This is then energized by an extremely stable low frequency generator. The reason for the cable is to eliminate loss of signal through possible holidays in the coating.

The receiving unit is calibrated on the land section at two points, one on each side of the river crossing. Calibration data is stored in a memory processor which is used in order to process incoming signals and to provide immediate depth information. After calibration of the electromagnetic system has been completed, the land section is located at 25 ft. intervals from normal cover to the water's edge. Depth readings together with Global Positioning System readings are taken and stored.

Prior to carrying out work on the water section, the depth sounding equipment is calibrated by lowering a plate at a known depth below the transducer, thus ensuring accuracy of distance from surface to the river bottom. Calibration of instruments is critical as final results rely on this basic information. By taking information relating to pipe depth and position at the water's edge on one side of the river, crossing to the opposite side and taking further readings, a base line is automatically drawn on the screen of the system monitor. An icon representing the boat is shown in position and tracks the boat's position. The boat is then driven at frequent intervals perpendicular to the line, as it crosses over the pipe. Immediate readings of pipe depth, water depth and position (GPS) are simultaneously obtained and stored.

It is normal to take approximately 40 readings across a 500 ft. river span at each run. A second run is carried out for verification purposes after calibration has been re-checked. This provides a great deal of information in order for drawings to be prepared, so providing the client with accurate information. Results may be down-loaded over a telephone line back to the main office or for emergency purposes can be drawn up at site. The results of this system have been recently checked at 104 ft. and 72 ft. and found to be within the tolerance level of 99.5% accuracy relative to actual depth.

The experience with this technique over the last few years in dealing with situations involving flooded conditions, has shown that it really requires suitable equipment to be always available in readiness for emergency situations. Field deployment is made much easier if an inflatable boat (such as a 16 ft. Avon) and engine are available on site, so that personnel are able to fly directly to disaster sites and avoid a possible lengthy journey towing a boat. If immediate drawings and maps are desirable, then facilities for print-out of results and a portable plotter should also be available.

River Flooding

In view of some of the recent problems (October 1994) that had been encountered in the lower San Jacinto River Basin, where heavy rains had resulted in severe flooding and pipeline exposure, a discussion took place on the subject. The increased water velocity had altered the course of the river flowline, with two major pipelines becoming exposed and failing during the week of October 17. These failed pipelines produced a significant oil spill and accompanying fire in the river. At the request of the Texas Railroad Commission and the Department of Transportation, all pipeline operators with crossings downstream of the Lake Houston Dam shut in their operations until such time as an underwater inspection could be conducted to ensure that the pipelines had remained covered. In addition to the lost production revenues, there was considerable concern that product remaining in the pipelines could be released causing additional damage, although eventually it was possible to bring the situation under control.

Some of the inspection operations and remediation techniques deployed to address these flood-threatened pipelines were described by Gordon Barksdale. These involved the use of inland diving techniques, and it is important to note that inshore sub-surface operations often require equipment, techniques, and personnel quite different from offshore operations. Similar recent situations had also recently occurred in the 1993 Mississippi River Flood and in the 1994 Georgia Flood of the Flint River Basin.

Inspection Parameters for Rivers

Pipeline inspection at major river crossings differs from offshore pipeline inspection, and several methods are appropriate where indicated. The inspection parameters fall into two general categories :-

- to determine if the pipeline has any exposed areas or free spans.
- to determine the pipeline's depth of cover beneath the mud line.

Inspection methods also fall into two categories, namely :-

- inspection through deployment of manned diving operations.
- inspection through deployment of electronic instrumentation.

Manned diving inspections can employ both physical contact to the pipeline accompanied by hand held electronic devices. Physical contact is accomplished by a low pressure water probe, and is accurate but has a very limited range - a pipeline buried in excess of 5 ft. is difficult to probe. The electronic instrumentation that can be deployed in a diving operation, is usually a single axis gradiometer and/or a hand held depth of cover sensor. Which method is most suitable is normally governed by the following criteria :-

- Ambient river current.
- The expected burial depth of the pipeline.
- Presence of water borne debris.
- Project logistics and safety considerations

It is also possible to undertake electronic instrumentation inspections without divers. The systems are operated in an "Active Mode" meaning a tone or signal is artificially introduced to the pipeline, or in a "Passive Mode" meaning the system senses the inherent magnetic field of the pipeline. Both methods rely on triangulation of the signal to delineate a distance measurement or depth of cover of the pipeline. The deployment of electronic instrumentation is governed by :-

- Ambient water depth (i.e. deep enough for small craft operations)
- Presence of contact access to the pipeline (i.e. a CP test station)
- Presence of foreign crossings, and/or bottom debris

Both diving inspections and electronic inspections require the support of horizontal positioning. Nowadays Differential Global Positioning or Total Station systems are the preferred equipment to delineate the XY coordinates of the data points in addition to confirming the XY coordinates of the pipeline. Water depth can be determined through the diver's pnuemofathometer and/or through an echo sounding system. It is critical that the water depth data be corrected to a known vertical control (e.g Mean Sea Level).

Problems at the San Jacinto River

The Colonial Pipeline break occurred at the San Jacinto River north of the I-10 bridge, where the river velocity was 14 ft/s with significant amounts of water borne debris. The break area, which prior to the flood had not been in the river, was still under rushing water, and the logistics were compounded by the oil spill and fire. The immediate problems were to determine the condition of the line at the break area, and at the main crossing in the river.

Diving operations were not possible due to the extreme current, since a water velocity in excess of 5 ft/s precludes effective diving inspection. Also ruled out were electronic instrumentation inspection, as an "Active Mode" system requires continuity of the line (the line was severed) and a "Passive Mode" system requires instrument deployment directly on the river bed. The high current and presence of debris were not favorable for deployment of this type of equipment.

Use of Sonar Imaging Equipment

For this particular crisis, it was believed that the most suitable equipment proved to be deployment of a Sonar Scour Vision System (SSVS). This is a high resolution sonar system that scans 360 degrees through both the vertical and horizontal axis from a single point station of survey. Although very useful for pipelines (including on the Mississippi River to delineate the free span area of a 16" pipeline located in a high flow area), the most popular use of such systems recently has been to conduct scour inspections of bridge structures during periods of high water velocity (which included the I-10 Bridge that was closed during this flood). The advantage of SSVS technology over echo sounders is that it provides 100% data closure over the survey area, and does so in real time providing the engineers with immediate information. In addition these devices can also be mobilized and deployed in very difficult conditions.

In the case of the San Jacinto River flooding, the immediate objective was to determine if the pipeline(s) were spanned or exposed. This can easily be detected, since if the pipeline is free spanned, it is automatically plotted as a higher elevation as compared to the natural bottom. The SSVS equipment does not itself determine the depth of cover of the pipeline, as the sonar operates at 675 kHz., meaning no penetration of the mud line is achieved. However, the survey would provide immediate data if the pipeline were exposed, in addition to a complete profile of the surrounding bathymetry.

Mobilization of the system required a 24 ft. survey vessel with a two man crew. The range of the system is from 5 meters to 100 meters radially, and the method is rapid in application. In the case of the San Jacinto River floods, it was possible to inspect nine pipelines for exposed pipe and free spans within one day.

On three inspections, the results produced by the sonar imaging equipment were deemed to satisfy the requirements of regulatory agencies, allowing the owners to return to production. Two inspections gave engineers tasked with repair operations the final information they needed to proceed.

As the flood lessened, the SSVS systems were used to survey the pipelines for spans, while the diving crews were conducting depth of cover surveys both with the use of physical contact (water probes) and hand held electronic instrumentation. After the water level decreased, diving operations provided the majority of the inspection data. It was noteworthy that most of the inspections were executed with no more information than the pipeline diameter and the location of the pipeline entry into the river, even though the condition of the inspected pipelines ranged from no exposure to free spans and exposed sections in the river.

Support of Pipe Spans

A common problem discussed was the formation of pipe spans created during construction when pipe is laid across a rock outcrop that protrudes above the bottom of the ocean, or when the natural sag of the pipeline will not allow the pipe to remain in contact with the bottom for support. Underwater pipe spans can occur during installation, or anytime afterwards, as a result of currents scouring the bottom. These spans can produce excessive pipe stresses and if allowed to increase in length can cause pipe failure. In addition the spans are subject to currents that can create vortices, which may cause pipe vibrations and pipe failure due to fatigue.

It was pointed out that there are several options for temporary support under these circumstances, depending on the length of span and the pipe stresses as a function of span length in air and water. In addition, it is desirable to consider the flood water current velocity (should heavy rains cause additional flooding) and the ability of a support system to raise the pipe span to reduce pipe stresses to acceptable limits. Available solutions include piles driven into the bottom equipped with pipe clamps, although this requires heavy equipment such as barges and cranes. Cement bags can be used, although again these can be heavy if air lifting into position is required. In addition, air bags can be used to lift the pipe in order to take the sag out of the span prior to completing cement bag supports. A means of attaching pipe to the supports is sometimes also required if renewed flooding is a possibility which might wash the pipe off the supports.

A solution that can be very convenient, especially in deep water, is to use telescoping pipe supports. These have been used in various jobs in Missouri and Texas during floods, and have been able to provide adequate pipe support during emergencies. Potential advantages include low cost, rapid deployment and a minimum of equipment required for installation.

Telescoping Pipe Supports

A telescoping pipe support system was described by Mr. Brian Webb of Tulsa, consisting of an integrated installation system using a small barge. The barge, pipe supports, diving equipment and personnel could be air lifted to the location, and the supports installed. The telescoping pipe supports were a single leg design, and the telescoping feature was designed to raise the pipe thereby reducing the pipe stress. The weight of the pipe filled with liquid in air was the basis of design to determine pipe support spacing and the minimum allowable deflection. Some small stresses sometimes also occur as a result of the single leg supports leaning away from the centerline of the pipeline. Single leg supports should ideally include a mud pad and cleat on the bottom of the support and a pipe clamp and fill valve at the top. Buoys can be attached to keep supports vertical when dropped on location by helicopter. A work barge is light enough to allow lowering on location by helicopter if necessary.

Installation requires placing the pipe supports and work barge on location. The work barge would normally be tied to the pipeline at the point to be supported. A work boat could bring the pipe support buoy alongside the work barge and the pipe support connected to the winch on the work boat. The pipe support buoy is then cut free and the pipe support clamped to the pipeline. A water pump on board the work barge can expand the telescoping pipe support to the desired elevation, which can be measured with a range rod. The installation procedure is then repeated until the span has been stabilized. Post pads can be installed after legs penetrate to refusal, to give additional support in case the legs settle. Adjustments of the supports can be made at a later date should span conditions change.

This procedure has been used successfully at four washouts experienced by Explorer Pipeline, including several dual-leg telescoping pipe supports from a central stockpile. These supports can be modified for long-term storage, ready for rapid deployment, so that almost immediate response can be undertaken to support pipe spans in abnormal situations.

Oil Spill Clean-Up Capabilities

A discussion followed on methods and plans for containing and cleaning up spills of liquid hydrocarbons. Dave Rechenthin described the capabilities of the industry cooperative group known as Clean Gulf Associates (CGA), for dealing with medium gravity crudes from exploration and production type spills in the Gulf of Mexico. This association is made up of some 147 exploration and production companies plus 2 gas pipeline corporations who operate in the Gulf of Mexico. Participation area is the Gulf of Mexico, US waters, from the Rio Grande River to the Florida Keys, including bays and estuaries, or the Intracoastal Waterway, whichever is further North. Equipment is located in nine response bases strategically located along the Gulf of Mexico coastline (Port Aransas, Galveston, Cameron, Intracoastal City, Houma, Grand Isle, Venice, Theodore, Panama City), as well as at Texas City. The equipment is dedicated to CGA members' use but can be released for use by non-member concerns by the management team, which is assisted by four standing committees involving some 22 professionals.

The annual budget is approximately $ 4 million, and costs are paid at 15% based on membership and 85% based on each member's share of liquid hydrocarbon production. The estimated replacement cost of the inventory dedicated to oil spill clean-up is over $18 million. Aerial dispersant spray capabilities will shortly be available in conjunction with Airborne Support Inc.. A prime contractor (Halliburton) purchases and maintains equipment as directed by CGA, which supplies each member with a comprehensive manual. However member companies are responsible for having their own spill response plans and to provide trained personnel to operate the equipment. Supervisors will advise members on spills, if requested, but will not supervise clean up operations

Equipment maintenance and testing is taken care of by 14 personnel dedicated full time to management, engineering, administration, maintenance of equipment, and training of operator personnel. All equipment is checked out, including running of engines, at least monthly. In addition to internal checks, the MMS inspects the equipment at least annually and has required actual deployment of each system at least once every four years. Participation has proved to be particularily valuable to members since MMS has a program of unannounced response drills whereby companies have to respond to MMS-described hydrocarbon spills.

At present the activities are limited to oil spill related matters on the basis that the association is an oil spill cleanup equipment resource. Periodic industry reviews are however carried out to assess capabilities and determine what changes are needed to meet the needs of the membership. For instance a study in 1990 resulted in ID Boats, open ocean containment boom, a shoreline protection boom and additional personnel.

SPECIAL WRITTEN CONTRIBUTION A

"COMMENTS ON THE NRC MARINE BOARD'S REPORT ON IMPROVING THE SAFETY OF MARINE PIPELINES"

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Abstract

The safety of the United States' undersea pipeline systems, in terms of both human safety and potential for environmental damage, is a major national concern. These systems extend for more than 20,000 miles, carrying almost one-fourth of the nation's natural gas production and more than one-ninth of its crude oil.

Several accidents in the late 1980s, which claimed more than a dozen lives, raised public and congressional concern about the safety of the subsea pipeline system. Its structural integrity and maintenance are also subject to question, for much of it was installed in the 1950's and 1960's. Both maritime accidents and pipeline structural failures could result in pollution of fishing areas and coastal lands.

Terms of Reference

The Minerals Management Service (MMS) of the U.S. Department of the Interior and the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation requested an interdisciplinary review and assessment of the many issues - technical, regulatory, and jurisdictional - that affect the safety of marine pipelines in U.S. offshore waters, including state waters. The National Research Council Marine Board appointed the Committee on the Safety of Marine Pipelines, and charged it with the following tasks:

- Review and analyze the historical causes of pipeline failures;
- Assess the state-of-practice and the potential for pipeline failures - whether caused by external, man-induced forces, seabed geotechnical conditions, or hydrodynamic ocean forces - and the means of mitigating them;
- Review and assess means for conducting right-of-way surveys and pipeline inspections;
- Assess the operation of pipeline safety systems and devices, and the maintenance and rehabilitation procedures for detecting and mitigating hazards and leaks;
- Assess periodic inspection, data collection, and analyses needed to evaluate the integrity of the pipeline systems;
- Identify alternatives for improvements in the regulatory framework and guidance for rule-making that may enhance pipeline system safety and environmental protection.

The committee excluded from consideration pipelines in harbors and inland waterways and those related to refinery and storage facility interconnections and pipelines in Alaskan state waters. The committee did not attempt a general survey of pipeline repair and rehabilitation techniques, and focused on measures to improve pipeline safety.

The greatest emphasis by far was placed on the systems in the Gulf of Mexico, where about 99 percent of the marine pipeline mileage is located.

The committee received briefings from the MMS, OPS, and the U.S. Coast Guard on these agencies' responsibilities in enforcing regulations, and their operational issues and problems. The committee reviewed the concerns of persons and organizations affected by offshore pipelines and their regulation, through briefings by pipeline operators and representatives of the fishing industry. It also received presentations on the dynamics of shoreline change and its influence on pipelines. The problems with safety data bases were explored.

Background

Since its first ventures into the shallows in the early 1950's, the pipeline industry has steadily improved its designs, materials, and techniques for construction, operation, and maintenance. Today pipelines are operated with confidence in waters as deep as 1,700 feet, with plans ready for 3,000 feet. Marine pipelines carry about one-fourth of the nation's gas production and one-ninth of its crude oil.

Several dramatic accidents in the late 1980's raised new public concerns about the safety and integrity of marine pipelines. In particular, two separate fatal incidents in which the fishing vessels Sea Chief and Northumberland, operating in shallow waters, struck pipelines that were no longer properly buried, were focal points. Pipelines must share the waters with some of the nation's busiest ports and most productive fisheries, and must retain their integrity for decades in the face of frequent storms, coastal erosion, and, in California, seismic activity. Hurricane Andrew, by closing down much of the marine pipeline network in the Gulf of Mexico for weeks in late 1992, brought home the economic impact of interrupted service, and the vital importance of the integrity of the marine pipeline system for the long term.

The Committee accordingly reviewed the causes of past pipeline failures (except for seismic activity); the potential for future failures; and means of preventing or mitigating them, including operational measures, inspection techniques, data collection efforts, and improvements in the regulatory framework and its accident reporting requirements.

The committee stated in its 1994 report that at that time the marine pipeline network does not present an extraordinary threat to human life. Offshore pipeline accidents involving deaths or injuries are disastrous, but rare. The most widespread risks are due to oil pollution, mainly from pipelines damaged by vessels and their gear. These risks can be managed with available technology, and without major new regulations, if enforcement of some current regulations is improved. Better coordination among operators and regulators in gathering safety data, assessing risks, and planning and implementing risk management programs is the most fundamental requirement.

Shared Regulatory Jurisdiction

Safety regulation of marine pipelines is shared by federal and state agencies. In the federal waters of the outer continental shelf (OCS), the OPS regulates nearly 13,000 miles of so-called transmission pipelines, and the Minerals Management Service about 4,000 miles of production pipelines. In state waters, OPS has jurisdiction over transmission pipelines, and the states over production pipelines. OPS certifies state agencies to enforce its regulations for intrastate transmission pipelines.

MMS has extraordinarily broad regulatory authority. Under the Outer Continental Shelf Lands Act of 1978, it issues permits and rights-of-way for all OCS activities, including pipelines, to ensure "maximum environmental protection." In pursuit of this goal, the agency sometimes also applies its regulatory requirements to OPS-regulated pipelines that begin on the OCS and extend to state waters. Implementation of the Oil Pollution Act of 1990 (P.L. 101-380) has expanded MMS's authority.

Safety Experience

Analysis of past pipeline failures is difficult, because data collection by federal and state agencies has been inconsistent and incomplete. MMS, OPS, and the Coast Guard all receive reports on pipeline failures for their particular purposes, but have never assembled a coordinated data base. Most state regulatory agencies have only rudimentary records.

Only for the Gulf of Mexico OCS did the committee find an organized and reasonably complete data base on pipeline failures, their causes, and their consequences. Even that information is insufficient to establish such important statistical connections as those between rates of corrosion leaks and pipeline age or product carried. This information cannot be used to find patterns in the locations of corrosion failures or anchor damage that would help in setting risk management priorities. Several important patterns do appear, however:

- Corrosion, although it was the reported cause of nearly half of the 1,047 OCS pipeline incidents recorded between 1967 and 1990, produced only about 2 percent of the pollution from pipelines.

- Damage from vessels (and especially from anchors and groundings) is dramatically more significant than corrosion as a source of pollution and other consequences, including deaths and injuries. Anchor damage alone accounted for 90 percent of the pipeline-related pollution on the Gulf OCS.

- A very few incidents have produced most of the pollution. The largest 11 pipeline spills, all caused by vessels, accounted for 98 percent of the pollution from pipelines.

- Deaths and injuries are rare. Six incidents, over 24 years, resulted in all of the deaths (24) and serious injuries (17) associated with pipeline failures. Some occurred as pipeline accidents on platforms and above the surface of the Gulf.

It must be emphasized that these patterns emerge from incomplete data. Most importantly, they do not reflect experience in state waters.

Maintaining the Integrity of Marine Pipelines

Although it is not a major source of oil pollution or other safety consequences, corrosion remains a troublesome inspection problem. Small pinhole leaks are a continuing concern. Repairs and inspection are extremely costly for underwater pipelines.

The uniform electrochemical characteristics of seawater make external corrosion protection simpler than it is on shore or on pipeline areas that are intermittently immersed, such as risers on platforms. Verifying the adequacy of protection, on the other hand, is more difficult offshore than onshore because access points to the pipeline are limited.

Internal corrosion is more difficult to locate and quantify. Operators can usually predict the circumstances in which internal corrosion will occur. Inspection and remediation techniques can be used in those situations.

In-line internal inspection devices, or "smart pigs," have been in use, with steady improvement, for more than 20 years. They have seen increasing use in pipelines onshore, and in a few marine pipelines. However, they are limited in several ways by the nature of piping configurations and of offshore operations. Physical access to suspected faults is more difficult and costly offshore. False indications of faults are common. The smaller and more accurate devices of the future are likely to see increasingly wide use offshore.

Avoiding Outside Interference with Pipelines

The most significant pipeline failures are those that result from damage by vessels and their gear. Impacts of anchors, nets, trawl boards, and hulls of cargo, fishing, and offshore service vessels and mobile drilling rigs can lead to major pollution incidents, costly repairs and replacements, and even injuries and deaths.

No available sensor technology allows moving vessels to detect pipelines at a distance in time to avoid possible contact with them. In most areas, sufficient pipeline depth of cover is the only practical way to reduce the chance of interactions with vessels. For this reason, regulatory standards and engineering practice require pipelines to be buried below the bottom (generally by at least 3 feet) in waters less than 200 feet deep, with coatings of adequate weight to keep them in place. A recent survey ordered of OPS-regulated pipelines found that 1.7 percent of the pipeline mileage in the Gulf of Mexico in less than 15 feet of water (enough to accommodate the drafts of large fishing and service vessels) had less than one foot of cover - most likely from bottom scour due to near-shore dynamic forces.

Retaining original depth of cover in the Gulf of Mexico is complicated by those dynamics, which feature large movements of sediments and a general pattern of shoreline erosion and retreat, modulated by severe storms.

Placing Responsibility for Safety

By law, the responsibility for safety lies with the operator. Regulatory standards are minimum requirements and must be supplemented by sound engineering and operating practice.

This observation does not minimize the importance of a strong and consistent regulatory framework. Regulatory agencies are responsible for setting appropriate policies for risk management on the basis of objective risk assessments. To do so, they need detailed and comprehensive information about pipeline failures, and they need the engineering knowledge to translate their priorities into standards that provide cost-effective solutions. In the case of marine pipelines, where several agencies are involved, a consensus about their priorities is needed.

Major Conclusions and Recommendations

The safety record of marine pipelines is a good one, but it can be improved. During the late 1980's, the Gulf of Mexico OCS experienced about one reportable pipeline incident every five days. Most of these were small leaks of gas or small oil spills caused by corrosion or some above water operation. Although it is estimated that petroleum hydrocarbons enter the Gulf of Mexico from river and stream runoff and from natural seeps in significant volumes (greater than the spillage from offshore operations and accidents), offshore oil and gas operations and tank vessel accidents are two areas where preventative action can possibly be effective in reducing pollution.

The volume of oil that enters the Gulf from the oil and water mixture produced from offshore wells (known as "produced waters") is estimated to be the largest source of oil into the Gulf from offshore oil and gas operations (which do not include ship transportation). The committee report addresses the second largest source of spillage from offshore oil and gas operations, that from pipeline accidents and line failures.

Pipeline failures and spills are reported to several different agencies, which have different reporting formats and information requirements. No agency coordinates the collection of all available information. The available data on incidents on offshore pipelines are correspondingly incomplete. The responsible agencies must improve the process of information gathering, archiving, analysis, and reporting.

Recommendation:
The regulatory agencies involved should develop a common safety data base, covering both state and federal waters, and periodically review their data requirements. The extended data base should include the information needed for risk and cost-benefit analysis. MMS, which has the greatest test experience and resources in data gathering, should coordinate this effort.

Safety planning can be improved. Modern risk analysis methods, using incomplete data supported by expert opinion about the nature and distribution of risks, can clarify priorities for risk management. The risks to human safety and to the environment due to failures of marine pipelines are not uniform across the Gulf of Mexico. A risk analysis approach that compares risks in different geographic areas (or "zones") would allow cost-effective risk management decisions.

Recommendation:
Safety regulations should be based on sound risk and cost-benefit analyses. Specifically, regulatory agencies should agree on a consistent risk management strategy for setting priorities about human safety criteria, and about the use of cost-benefit analysis for the reduction of property and environmental damage.

Enforcement of safety regulations also reflects a lack of coordination among agencies. This situation is largely related to the great differences in the scope and approach of the enforcement programs of OPS and MMS. The marine portion of the over-all OPS jurisdiction is small - less than 1 percent of the total OPS mileage nationwide, and presents little risk to public safety and the environment compared with land lines that traverse densely populated and industrial urban areas.

MMS assigns 70 inspectors and equipment to the Gulf of Mexico region to make regular on-site inspections of all safety systems under their jurisdiction. OPS assigns only 2 of the 30 inspectors on their nationwide staff to this region. Although OPS also has the services of approximately 250 state inspectors who are assigned (by agreement with the OPS) to both interstate and intrastate pipeline inspection, these personnel are not available for OCS inspection assignments.

These differences in resources and approaches focused on marine pipeline inspection, reflect differences in the physical location of facilities and the safety issues faced by the two agencies. It appears likely that OPS enforcement personnel are too few to cover adequately the 13,000 miles of marine pipelines and more than 160 operating companies in the Gulf of Mexico region of the OCS that are under OPS jurisdiction.

Recommendation:
Make better use of inspection resources and help integrate enforcement of MMS and OPS marine pipeline safety regulations. It is recommended that enforcement of OPS regulations offshore be performed by the MMS, through an interagency agreement or redefinition of the Memorandum of Understanding that defines the jurisdictional division between OPS and MMS. Such a system would continue OPS's role in regulating offshore pipelines by bringing to bear MMS's greater resources.

Another regulatory discrepancy is apparent in the MMS and OPS requirements for internal inspection of pipelines. MMS has established a general requirement for the use of in-line inspection devices where practicable. OPS is studying the matter, under Congressional mandate. The vast majority of today's marine pipelines cannot physically accommodate smart pigs. Modification of pipelines generally would be impractical and uneconomic. The current devices are relatively inaccurate in locating flaws.

The use of smart pigs offshore will not be widely practical until further technical improvements are made, especially in the reliability and accuracy of three-dimensional anomaly measurement, in the compactness and maneuverability of smart pigs themselves and in an accurate positioning system developed for geographical location of troublesome anomalies.

Recommendation:
Marine pipelines already constructed should be exempted from federal or state requirements for the use of currently available smart pigs for external or internal corrosion detection. New pipelines running from platform to platform or platform to shore should be designed to accommodate smart pigs whenever reasonably practical.

Many leaks are first detected through visual sightings by parties other than the pipeline operators and who generally cannot identify the operator of the pipeline. Often there is no agency or entity that can establish the responsible party in a timely fashion.

Recommendation:
MMS should coordinate an effort by appropriate federal and state regulatory agencies and industry to establish a system through which leaks detected by third parties can be reported to a single agency or notification center with continuous coverage around the clock. This one central location should have a comprehensive data base permitting easy identification of the operator of any marine transmission or production line based on the reported sighting location. Pipeline operators, in turn, should have 24-hour telephone numbers or a means of immediately contacting all other pipeline and platform operators who must take action.

No sensor technology is available to permit moving vessels to detect nearby pipelines and thereby avoid them. An obvious but difficult problem is the control of the mooring of supply and service vessels in areas adjacent to offshore platform installations. Clear communications between vessels and offshore platform operators would help avoid these risks.

Recommendation:
In areas where supply and service vessels operate adjacent to fixed platform installations associated with high densities of pipelines or flowlines, permanent mooring systems should be considered. Platform operators should be required to provide detailed and timely information to vessel operators on the configurations of local pipelines or flowlines. New pipelines adjacent to platforms should be installed whenever possible in well defined "corridors."

In shallow waters (generally less than 200 feet deep), the best protection against the interference of vessels and pipelines, generally, is burial of the pipelines. Pipeline installation must take into account detailed knowledge of soils, currents, and shoreline dynamics processes.

The committee had no information leading it to believe that the initial burial depths required by regulatory agencies are not adequate. Pending further study, the current regulatory standard for depth of initial burial must be considered adequate, if it is maintained through the life of the pipeline.

Much of the Gulf shoreline is eroding rapidly. This erosion may expose pipelines buried at installation and can be accelerated by the trenching methods used to install pipelines across the shoreline. The directional bore method of installing pipelines under beaches without breaking the surface minimizes this problem.

The need for periodic inspections of pipelines, to ensure that they do not lose cover or become exposed, is not addressed in standard industry practice or in regulations.

Recommendations:
Geotechnical studies of soil conditions, with sampling at intervals determined by local site conditions, should be required as a condition of marine pipeline construction permits. Permitting and regulatory agencies should work with industry to develop criteria for specific gravities of marine pipelines in varying soil environments.

To provide baseline data for subsequent depth of cover and bottom status surveys, newly installed pipelines should be surveyed, and their depths of cover recorded, with reference to Global Positioning System locations.

All agencies involved in the permitting of pipelines crossing shorelines should require the use of the directional bore installation method wherever feasible.

In waters less than 15 feet deep, periodic depth-of-cover surveys in the Gulf of Mexico should be scheduled according to the specific local shoreline and seabed dynamics, and the passage of severe storms.

Pipeline operators and regulatory and permitting agencies should conduct studies to determine the appropriate standards for initial depth of burial under various shoreline and seabed conditions, using the results of the recommended periodic depth-of-cover surveys.

Abandonment of marine pipelines will continue to increase as producing fields reach maturity and are shut-in. Most of these abandoned lines are in shallower state waters. A properly abandoned pipeline poses no risk to public safety or to the environment.

Recommendation:
Pipeline abandonment standards and regulations should include a requirement for a one-time inspection at the time of abandonment to verify that abandonment requirements were met.

Summary

This paper has discussed the eight recommendations resulting from the Marine Board Study Committee appointed to review and assess the technical, regulatory, and jurisdictional issues regarding the safety of U.S. marine pipelines. There was no major deficiency found in the manner in which marine pipelines are constructed, operated and regulated.

It is apparent however, that better methods of understanding and evaluating existing inadequacies in the regulatory sector are needed to result in a comprehensive and improved safety climate. This can be achieved by re-aligning all concerned regulatory agencies' procedures and responsibilities to common and comprehensive objectives.

Industry and government will co-operate, as in the past, to develop the basis for improving safety wherever the need exists. The past 30 to 40 years of design, construction, operation and regulation of offshore pipelines has been a commendable joint effort which should be recognized for all that was accomplished. It is important to confront those areas where improvement is needed and can be made.

SPECIAL WRITTEN CONTRIBUTION B

"RECENT R&D FINDINGS FOR NEW AND CHALLENGING PROJECTS"

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Abstract

Since the pioneering construction of the TRANSMED pipeline system across the Sicily Channel in the late 1970's, offshore pipeline technology has been progressing towards increasingly difficult environments. New projects planned are now venturing far beyond the challenges of the recent past, sometimes requiring the development of new equipment and relevant technologies.

The scope of this paper is to present recent research efforts aimed at tackling the main design aspects of these future challenges. Particular attention will be given to the experiences and achievements of the last few years in oil and gas pipelines across the European Continental Shelf, e.g. in the central and southern North Sea and across the Mediterranean Sea. Technologies, tools and specific criteria will be discussed.

Introduction

During the early 1970's, a number of studies were carried out to confirm why offshore pipelines should be considered the safest and most economic system for transporting large quantities of hydrocarbons from offshore production fields to coastal terminals, and for long distance transportation across sea straits or coastal waters (e.g. Carbone et al., 1985).

It was necessary to develop new materials and pipe fabrication technologies from those originally developed for onshore pipelines or for relatively straightforward marine conditions such as encountered in the coastal areas of the Gulf of Mexico and in the Arabian Gulf. This effort placed the industry in a position to tackle the difficult environmental conditions of a number of strategic pipeline crossings planned at that time. The first lines linking Tunisia to Sicily across the deep waters (610 m.) and difficult seabeds (outcropping rocks) of the Mediterranean Sea (completed in 1981 and recently extended as shown in Figure 1, Albano et al., 1992) and also the major network of pipelines crossing the stormy waters of the North Sea and the deep depressions of the Norwegian Trench, (Atken et al., 1985), are clear examples of the difficulties overcome in the implementation of new projects in the late 70's.

The efforts made by groups devoted to research and development in new deep-water technologies (such as the Deep Water Pipeline Group established by Shell Development, incorporating more than 30 international companies, Langner and Ayers (1985)), produced the results necessary to make implementation of deep water pipelines feasible and reliable both in technological and economic terms. The satisfactory performance of these systems for well over a decade of operation, is an indication of the effectiveness of the technologies developed to tackle these new project conditions. This has resulted in the prospect of pipelines links until recently considered unviable (Palmer, 1994).

Coping with Future Challenges

New prospects are now considering entry into Norwegian fjords across narrow corridors, rocky outcrops and deep troughs (also involving peculiar patterns of on-bottom currents caused by the regular exchange of water between the fjord and the ocean), (Breivik, 1994). In these projects, the very uneven seabed is such as to shift technical interest towards estimates of investments associated with the preparation of the seabed before pipelay, specification of the required accuracy of laying along the selected corridor, anticipation of unacceptable free spans across the repeatedly encountered rocky peaks, and development of remedial measures for these areas, before pressure testing and operation of the lines. Figure 2 shows a characteristic outline of such seabed scenarios: a stretch of pipeline resting on the crests of seabed undulations and on gravel sleepers which provide additional supports against excessive free spanning lengths.

A submarine pipeline is also being designed to carry gas from Morocco to Spain across the Straits of Gibraltar (Baker, 1993). In this area, the regime and intensity of the currents from the surface down to the seabed, will make the construction phase challenging. Moreover, the requirements for stabilizing and correcting the configuration of the pipeline on the seabed, are particularly demanding. In fact the resulting weight of the pipeline requires considerable upgrading of the equipment currently available for installation, or perhaps even development of new equipment. Figure 3 shows the selected route and the seabed profile for such a pipeline.

Recent studies (Estaugh, 1994) envisage a subsea pipeline between Oman and India that will cross the Indian Ocean abyssal plain and very steep slopes at unprecedented depths of over 3000 m, in an underwater environment affected by slides, turbidity currents and earthquakes, as illustrated in Figure 4. Project requirements call for a pipe diameter of more than 24" which is extremely large considering the high external pressures caused by the water depth. Project development currently includes comprehensive studies on material and thick wall steel-pipe production technology, together with basic design activities for the development of special equipment for assembling and installing a pipeline in such deep waters (Rosa and Brandi, 1994).

Other areas of deep-sea pipe laying currently in the planning stage, include both traditional areas such as the deep water sectors of the Gulf of Mexico, and areas until recently untouched such as Far-East Asia. In the latter, a Natural Gas Pipeline Network is being considered, as illustrated in Figure 5.

In more traditional areas such as the central and southern North Sea, with existing pipeline networks linking the rich gas deposits to the European Continent as shown in Figure 6, topics of major interest are the reduction of project and operational costs. This is planned to involve both the upgrading of existing transport systems, and the adoption of new pipeline systems in the face of more rational design criteria.

Recent experience shows that for a pipeline laid over a difficult sea bed, costs can be approximately divided as follows: 40% for installation, 20% for pipe material, 30% for seabed preparation and remedial measures on the as-laid pipeline, 10% for surveying and engineering. In contrast, for more traditional lines such as that linking the Norwegian offshore gas networks and the mainland, the cost of materials can reach 40% while cost of seabed preparation and remedial measures can be as low as 10%. These figures, for both cases of difficult and "traditional" crossings, show that high quality engineering, even for an apparently simple product, is vitally important for the project economics of future challenges.

Likewise research is an essential activity for the development of the technology needed to optimize and propose tailor-made solutions to specific problems. This is represented in deep-sea and difficult areas by aspects such as: route selection in harsh environments, assisted and tailored installation techniques, difficult seabed preparation technologies, technologies for remedying on-bottom pipeline configuration to guarantee a life span structural integrity, the diagnosis of potential dangers and consequently the development of repair technologies in such conditions, etc..

There is also interest in offshore pipeline technology in reviewing and revising those criteria inherited from onshore pipeline technology. New design formats and rationally based safety factors, which may be different depending on the products, the operating strategies, the different environments etc., now attract a large share of research resources, as the economic implications are considerable. A striking example of this is the present attention directed towards the rationalization of wall thickness requirements for pressure containment (Verley et al., 1994), some of which are now over fifty years old.

For a large diameter gas trunkline, the reduction of a few millimetres in wall thickness could mean many tons less of steel and consequent significant savings on material costs. Taking this relaxation of hoop stress criteria further, it may be acceptable for an installed pipeline to operate at pressures higher than planned. This would give rise to a richer gas inventory and higher terminal flow rates. The economic implications of applying such new criteria to networks operating in the North Sea, or to Mediterranean pipe-links (especially associated with new margins in the seasonal management of the flow rate) are substantial.

There are also aspects of pipeline design that require an "in-depth" theoretical approach involving sophisticated simulations and, at the same time, are strictly related to the capacity of the construction equipment and procedures. This requires close liaison between advanced approaches and construction issues. For example, many North Sea projects involve shallow waters of the European Continental Shelf where pipelines are exposed to harsh climatic conditions and sediment instabilities. In these cases, a multi-disciplinary approach is required to relate different aspects such as concrete coating criteria for the stabilization of the pipeline in the short term, lay ability for a given equipment, construction schedule, surveying, and burial criteria for long-term stabilization and protection. Sophisticated simulations are necessary to anticipate the possible changes over time of the pipe-seabed configuration, and results need to be carefully assessed with regard to practical considerations.

Integration between advanced engineering and construction issues is even more important in deep waters, such as the difficult sea beds of the Mediterranean Sea, or at the rocky entries to Norwegian fjords. In these circumstances the remedial works needed to guarantee the structural integrity of the pipeline for its entire operating life span, become an important economic consideration. Anticipating the attainable configuration of the pipeline on the actual seabed depends on the quality of surveying and on the capacity of the laying equipment. In these cases, analysis of the laying procedure and operating conditions of the pipeline are necessary to determine its behaviour on the irregular seabed and to permit an estimation of the work necessary for the preparation of the seabed and an approximation of the remedial actions required on the as-laid configuration. Moreover contingencies in the construction and start-up stages are a major concern that may upset original estimates of investment cost.

In-Place Stability on Erodible Seabeds

Among the present offshore pipeline projects in the North Sea, those related to gas transportation from the huge Norwegian fields down to Middle Europe coasts are undoubtedly the most important ones (Killerud and Solberg, 1992). A peculiarity of these projects is the installation and operation of large diameter pipelines in shallow waters. The areas crossed are affected by severe meteo-marine conditions and by seabed erodibility, giving rise to extensive bedform activity such as sand waves. Moreover, these areas are severely impacted by human activities such as fishing, ship traffic and offshore operations.

Figure 7 shows the congested pattern of ship lanes and channels crossed by the ZEEPIPE in the Dutch and Belgian sector of the North Sea. On average, more than 50,000 merchant ships per year cross the pipeline, which requires protection in certain areas against interference from unplanned anchoring operations or, at worst, impact from sinking ships. Pipeline design is therefore substantially governed by in-place stability and protection criteria against third party activities. Furthermore, the huge overweighting required for the on-bottom stability may affect layability, even for the most advanced laying vessels. If post-trenching is required along hundreds of km. to ensure in-place stability, the construction schedule may be significantly affected.

In addition seabed activity can induce substantial variations of the pipeline configuration, generating unexpected exposures and suspended spans. This considerably influences both the stability and protection requirements, as well as demanding extensive construction and operational survey programs (Anselmi and Bruschi, 1993). Sand wave migration, extensive sediment transport and liquefaction of backfill can unexpectedly expose a pipeline to storms and jeopardise the structural integrity especially in the presence of free span development (Jiao and Bruschi, 1991). To achieve an appropriate design in such circumstances, trenching or burial may be needed. It may be necessary to evaluate the time scale and the extent of erodibility of the seabed, of scouring and free span development, of the potential for surface layer liquefaction and self-lowering.

The simulation of pipeline response to a migrating pattern of sand waves, leads to a rectilinear configuration of the pipeline in the long run. Figure 8 illustrates the potential behaviour of a pipeline resting on the crests of sand waves as a consequence of considerable migration or modification of the wave pattern. The criticality of temporary conditions of exposure and suspension may result in a trenching profile ruled by environmental hazards and free spanning criteria imposed by fishing activity. Sometimes, full utilisation of the deformation capacity of the pipeline cannot be achieved. Due to the uncertainties associated with the nature of the environment, probabilistic methods can be used to formulate specific design criteria.

Optimum concrete coatings for in-place stability and burial requirements are strictly related to the environment i.e. water depth, environment conditions and seabed nature (Bryndum et al., 1993). As shown in Figure 9, the pipeline configuration on sandy soils may be: resting on sediments due to good bearing capacity; significantly embedded just after laying due to loose and poorly packed surface layers; free spanning due to intermittent scouring without any evidence (trend and magnitude) of self-lowering after a certain interval of time; or showing a clear susceptibility to self-lowering through surveying logs. The dynamics of pipeline-seabed interaction can change one configuration to another and it is impossible to state whether it would be better or worse with respect to in-place stability. Mathematical modelling calibrated by using laboratory and in-field data can be used to tentatively predict the expected performance with respect to: erosion, free span formation and development, potential lowering under fluid forces, and sediment transport.

The achievement of the required targets can be properly scheduled by adequate behavioural monitoring of the as-laid pipeline. Design analyses have to identify pipe concrete thickness layable and stable in temporary and operating conditions, and, where not stable, to define burial criteria. As-laid and self-burial surveys may confirm predictions and assist decision making. Surveying the configuration of the pipeline with respect to the seabed just after laying and then after one winter season, can be used as an in-field measurement to assess seabed conditions along the route. Where conditions permit, the trenching required can be reduced.

Figure 10 shows the results from a survey performed on the ZEEPIPE pipeline in the Dutch sector, south of the Dogger bank after one year, and its interpretation in terms of self-lowering. These surveys confirmed the most optimistic forecast of self-lowering based on theoretical modelling. A number of studies aimed at formulating the requirements for concrete coating and trenching, were performed during the detailed design stage, including evaluation of hazards resulting from exposure and scour-induced free spanning during the first winter season. The post-trenching strategy, based on this and on estimates of the potential for self-lowering, resulted in a saving of approximately 75 km. of trenching.

From the issues raised above, and considering the in-place stability criteria currently in force, it seems that the interaction between a pipeline and an erodible seabed is still a grey area, despite recently issued guidelines for in-place stability (Veritec, 1988; AGA, 1988). Joint Industry Research Projects are working on these topics and, in addition, a great deal of data from projects such as the ZEEPIPE after 3 years experience or the DONG pipeline after a decade of inspection findings (recently described by Krogh and Nielsen, 1993), are currently available. It is hoped that this will give rise to new efforts to issue improved guidelines for in-place stability of pipelines on erodible seabeds.

Installation Criteria

The gas transportation system envisaged in the North Sea targets large diameter pipelines to be laid on a seabed about 350 m. deep. Several studies have investigated the laying of large diameter pipelines in deep waters. It has been shown that laying large diameter pipelines in deep water is the severest technological challenge using present equipment (Anselmi and Bruschi, 1993).

Figure 11 shows the layability curves of a large diameter 40" pipeline in 350 m. water depth, from different third generation laybarges (submerged weight as a function of lay pull capacity, for traditional laying criteria applicable to line pipe steel API X65 - 0.2% strain on the overbend, 0.85 SMYS on the sagbend). These curves demonstrate the limitations of third generation laybarges with respect to the layability of large diameter pipelines in deep waters. The lay capacity could however be extended if the current design criteria were relaxed to allow strain states at the stinger higher than those allowed today (Sriskandarajah and Mahendran, 1992).

Studies are being conducted to determine from computer-aided laying simulations, which parameters (such as length and geometrical configuration of the stinger, pulling force at the tensioner etc.) could undergo upgrading changes to improve laybarge capabilities. The most critical of such simulations are those relating to the dynamic response of the pipeline to the motion of the laybarge, which, in turn, are caused by the encountered seastates, as extensively discussed by Bruschi et al. (1994).

For a large diameter pipeline designed to be layable by the most recent generation of lay barges by reducing the submerged weight, even a slight dynamic excitation from the laybarge can be critical. Inertial forces (e.g. from steel and added mass acting on the pipeline, and due to even small oscillations of the laybarge) can be extremely high and can result in over-stress conditions at the exit from the stinger. If the static state of stress is close to critical values, stress (and strain) will soon exceed allowable levels even for mild seastates. Based on the assumptions of Figure 11, Figure 12 shows the peak strains under dynamic conditions on the last roller of the stinger - note that dynamic criteria require peak strains to be less than 0.25%.

The dynamic behaviour of the pipeline is even worse if the laybarge is provided with a floating stinger instead of a rigid one. The periods associated with such wave heights are such that laybarge response in pitch can vary considerably. For a given wave height, the variation of the response in pitch due to periods associated with these wave heights, can be considerable, with an obvious impact on dynamic pipeline response. A pipeline laid by "S" laying suffers especially from oscillation of the laybarge in pitch. Under these circumstances, a pipe laying schedule can be seriously affected by even mild weather conditions.

Some confusion still exists on the principles that govern the selection of the most suitable design format for laying criteria - namely whether to use strain-based criteria in the event of a deformation-controlled configuration like on the stinger or on a seabed with which the pipeline can cope, or the more traditional stress-based criteria in the event of a load controlled configuration like pipe bending during laying and in the free span which forms on an uneven seabed. This decision is important to select safety factors that are consistent with the experimental data on which such criteria are determined. Indeed, collapse and local buckling criteria currently in force do not necessarily reflect the state-of-the-art technology, in particular concerning safety factors (Bruschi et al., 1993). As an example, Figure 13 shows the safety factor for collapse limit state as calibrated by structural reliability methods.

Considering also strength design against external over pressure, the effect of the type of material (in particular strain hardening capacity, type of manufacture - notably the UOE technology for very large diameter pipelines (Kyriakides et. al., 1991), are not accounted for in the design of large diameter pipelines in deep waters. The existing guidelines for the assessment of minimum wall thickness against collapse and for designing buckle arrestors, are therefore incomplete.

Relaxing laying criteria requires a comprehensive analysis, including all the possible laying scenarios and relevant targets. Strains higher than the currently permissible ones could be accepted on the stinger, in pipe sections corresponding to roller locations where the line is only slightly subjected to dynamic forces. Indeed this makes the stinger slope angle at the tip higher, allowing a higher dynamic differential strain without modifying the upper limit (Bruschi et. al., 1994). Allowable values should be determined after taking into account the presence of concrete coating.

It should not be forgotten that the field joints of concrete coated pipes act as strain concentrations (Lund et al., 1993). Figure 14 shows the strain concentration at a field joint as a function of concrete thickness, demonstrating the potential problems with thick concrete coatings, especially in load controlled conditions (as on the sagbend). For non-coated pipe, less strict criteria could be adopted, but cyclic strains in the non-linear region of the material properties should in any case be avoided (Shaw and Kyriakides, 1985) since strains can accumulate in the line section at the stinger exit and affect the pipe strength capacity against external over-pressure at the sag bend.

Current studies are directed to introducing limit state approaches for the offshore pipeline technology. Unfortunately, the formulation of such lay criteria must be checked for different laybarge characteristics and equipment. To do this properly, it is necessary to carry out exhaustive analyses of the seastate conditions likely to be encountered, to account for statistical uncertainties in both the stress and strain states of the line in the S-shaped configuration, to include the range of variation of laying parameters such as submerged weight and lay pull, and to analyse the effect of different laying scenarios. In principle, however, this will result in more rationally based and documented lay criteria.

Uneven Seabeds

Several activities have been carried out since the 70's by companies on the subject of uneven seabeds (Celant et al., 1982), due partly to new plans for pipelines crossing very uneven seabed areas. A major difficulty is related to the fact that the design process for such a pipeline requires multidisciplinary activities to determine the acceptable configuration on the seabed, based both on static strength and on fatigue life criteria. The seabed preparation works which may be necessary to guarantee the structural integrity of the pipeline, could have a considerable cost impact. The impact could be still significant, although less critical, in the event of extensive free-span rectification works just after laying, while it would be minor when a less restrictive schedule is acceptable.

As an example, Figure 15 shows a gravel berm bearing a pipeline in the middle of a free span, for which stability under seismic excitation must meet criteria for load bearing structures. With respect to this, acceptance criteria put forward are often questionable. JIR Projects carried out during the second half of the 80's (e.g. Tassini et al. 1989) and completed in the early 90's (Tura et al., 1994), highlight the strong interest in this field from oil and gas companies. In general, the definition of the limit free span length beyond which it is necessary to take remedial measures, involves aspects which often cause misunderstanding.

In the event of a random sequence of free span lengths, the structural behaviour of the entire stretch is fully correlated and needs a comprehensive static and dynamic characterization (Vitali et al., 1993). In fact, the complexity of the interaction pattern between adjacent suspended lengths is such that the concept of maximum allowable free span length no longer applies, at least as conventionally applied to offshore pipelines resting on a very uneven seabed profile. A new approach to free span assessment is therefore required to account for the calculated static configuration achieved by the pipeline laid on the actual seabed profile.

The concept of maximum allowable free span length must be replaced by an approach where, given the static and dynamic characterisation of the sequence of free spans and supported lengths, free spans having either unacceptable usage factors on their shoulders or a frequency lower than the cross-flow cut-off frequency, are identified. Figure 16 shows the coupling of free oscillation of adjacent free spans, and demonstrates the susceptibility of free spans to oscillations.

A new concept in offshore pipeline design is the cross-flow cut-off frequency, defined as the minimum value of the natural frequency of a free span in the vertical plane over which cross-flow oscillations are expected not to occur. It is based on a characteristic current associated with an estimated probability of exceedence. With this new design format, a safety factor can be introduced, combining the partial safety factors applied to the calculated natural frequency and to the cross-flow cut-off frequency. This allows the probability of occurrence of cross-flow oscillations to be quantified in a rational way, as in the case of other limit states.

An extensive study of laying operations is extremely important, as lay parameters can be optimized in order to produce a pipeline configuration coping with the uneven seabed. In fact, a displacement controlled configuration is desirable as it can be designed according to permissible strains, as opposed to a load controlled configuration for which more restrictive stress based criteria are usually mandatory. Permissible strain due to bending curvature imposed by seabed unevenness must be adequately investigated and defined, in terms of the: a) strain causing excessive ovalization or flattening of the pipe section; b) strain provoking collapse and local buckling in the presence of external overpressure, bending moment and/or axial force; c) strain triggering unstable fracture phenomena from a possible initial defect at the girth weld.

Unfortunately, under most circumstances it is impossible to exclude situations where the pipeline is in touch with the seabed for short stretches and free-spanning in the remaining sections. Since the state of stress is critical at free span shoulders, it is worthwhile to consider a certain safety margin between applied stress and yield stress during pipe laying on the uneven seabed. This is in view of free spans longer than those envisaged by the analysis carried out over the profile during the design stage. Theoretically, the safety margin should depend on several factors, such as the accuracy of the route profile, the regularity of the laying corridor, the accuracy of the laybarge when laying the pipe within the corridor, and the ability to predict the pipeline configuration on the seabed once laying operations are completed.

Figure 17 shows the equilibrium configuration of a pipeline on an uneven seabed in accordance with two different design solutions, both meeting international standards. The gravel volumes required to correct excessive free spanning are shown, with specific emphasis on the implications of local features (defined here as those requiring gravel sleeper higher than 5m.).

Extensive ROV surveying and assisted laying represent a promising way to tackle pipe-laying on very uneven seabeds. It would be desirable for laying contractors and operators to supply laying barges with monitoring systems designed for: assessing the effect on the structural response of the pipe when adapting the laying parameters to the actual conditions or when a variation, such as the actual seabed profile as compared with the "before laying" profile, arises; monitoring "while laying" special procedures, such as laying an overweighted pipeline section, which may be in certain circumstances a very effective method to correct spanning lengths; displaying in real time the expected behaviour of pipe seabed interaction for the pipeline length already laid and, in particular, for the most critical stretches where "while-laying" remedial measures are adopted.

Figure 18 shows the flowchart of a prototype simulation system developed within the framework of R & D activities, and representing the supervision procedure for the TRANSMED pipeline construction. The implemented software can acquire the parameters from the laybarge monitoring system (trim motions and reaction on the rollers), predict the laying free-span and touch-down point on the uneven seabed, process the information from a ROV which controls the number of pipe joints and relevant position on the local bathymetry at a given distance from the touch-down point, identify the vertical projection of the laybarge position on the bathymetric map from the surface positioning system of the laybarge, compare the calculated route with the theoretical one used for the detailed engineering, display on-line information in such a way as to be aware of the situation both on the stinger and on the seabed, and further display the effect of corrective measures where needed.

Project experience and actual environments have shown that, when a pipeline has to be laid on a very uneven seabed characterized by rocky peaks and three dimensional unevenness, the design and installation criteria might not be sufficient to guarantee project integrity against construction contingencies (Burattini et. al., 1993). In these cases, project integrity requires assisted laying in order to allow on-line verification of the design, possibly even re-designing during installation of the pipeline and if necessary performing while-laying remedial measures.

Conclusions

Offshore pipeline technology over the past decade has included some milestone projects. A series of specific studies carried out to support crucial design options and develop innovative solutions has improved our ability to properly define the near-seabed environment and to anticipate pipeline behavior. Simulation tools have been developed for proving the integrity and durability of proposed solutions under different load conditions from installation to operation. This enables validation of both standard and advanced concepts as required by International Regulatory Bodies. In many circumstances, new construction technologies have been implemented and equipment improved.

In addition, new challenging projects may need further innovation and new concepts. Extensive project experience has shown that the behaviour of a pipeline is a complex function of numerous parameters. Physical quantities and interpretive models used to assess structural integrity are affected by uncertainty. Some probabilistic analysis should therefore be included in the formulation of design criteria. At the present time, the rationalization of design and operating criteria is of key importance for future projects requiring considerable investment costs.

In this respect, the offshore industry is encouraging the use of new design criteria for submarine pipelines, based on the rational treatment of limit states as evidenced by failure modes experienced in operating systems. The new approach is expected to provide safety levels appropriate to particular project- and site-specific risks, which can then rationally tailor the safety and cost-effectiveness of proposed solutions. This applies equally to existing transmission systems required to operate beyond their original design life or design criteria.

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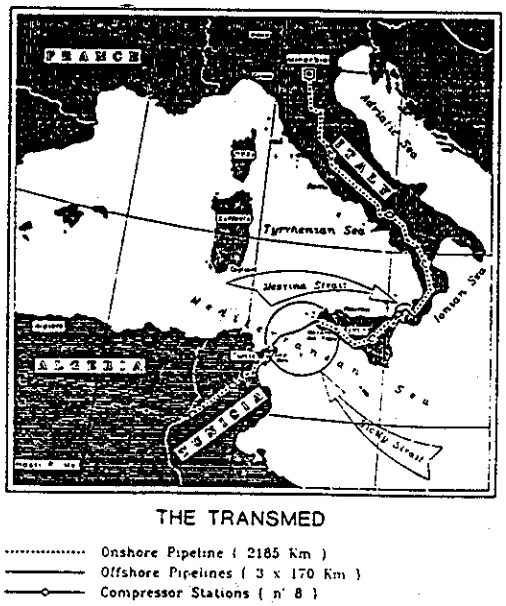


Fig. 1 - The Transmed Pipeline System (No.3 OD 20" and No.2 OD 26")

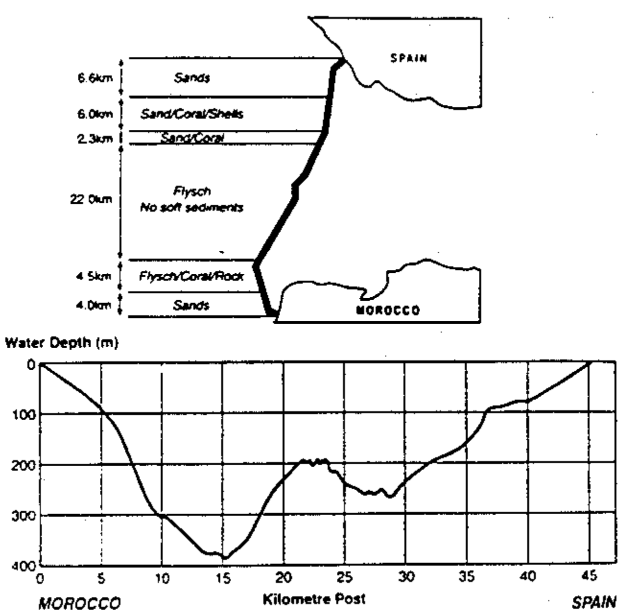


Fig. 3 -The crossing of the Strait of Gibraltar (No. 2 OD 22")

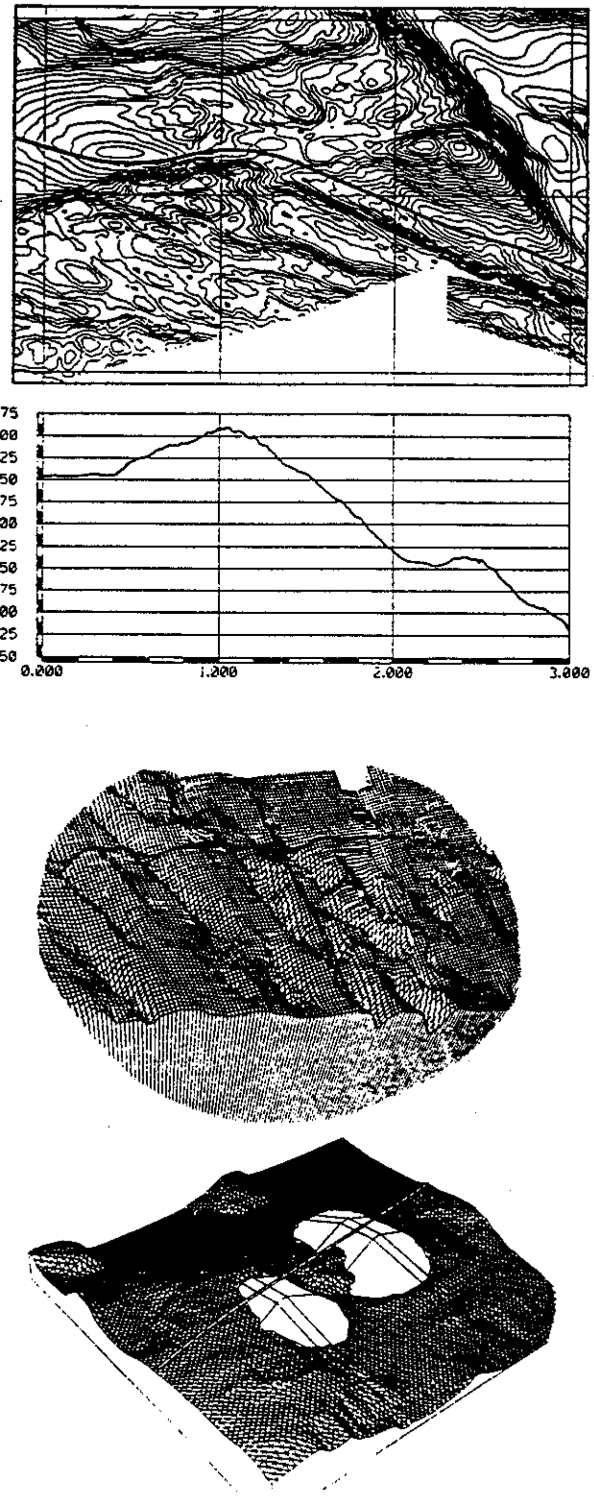


Fig. 2 Routing across uneven seabeds and characteristic seabed preparation works at the entrance of Norwegian fjords

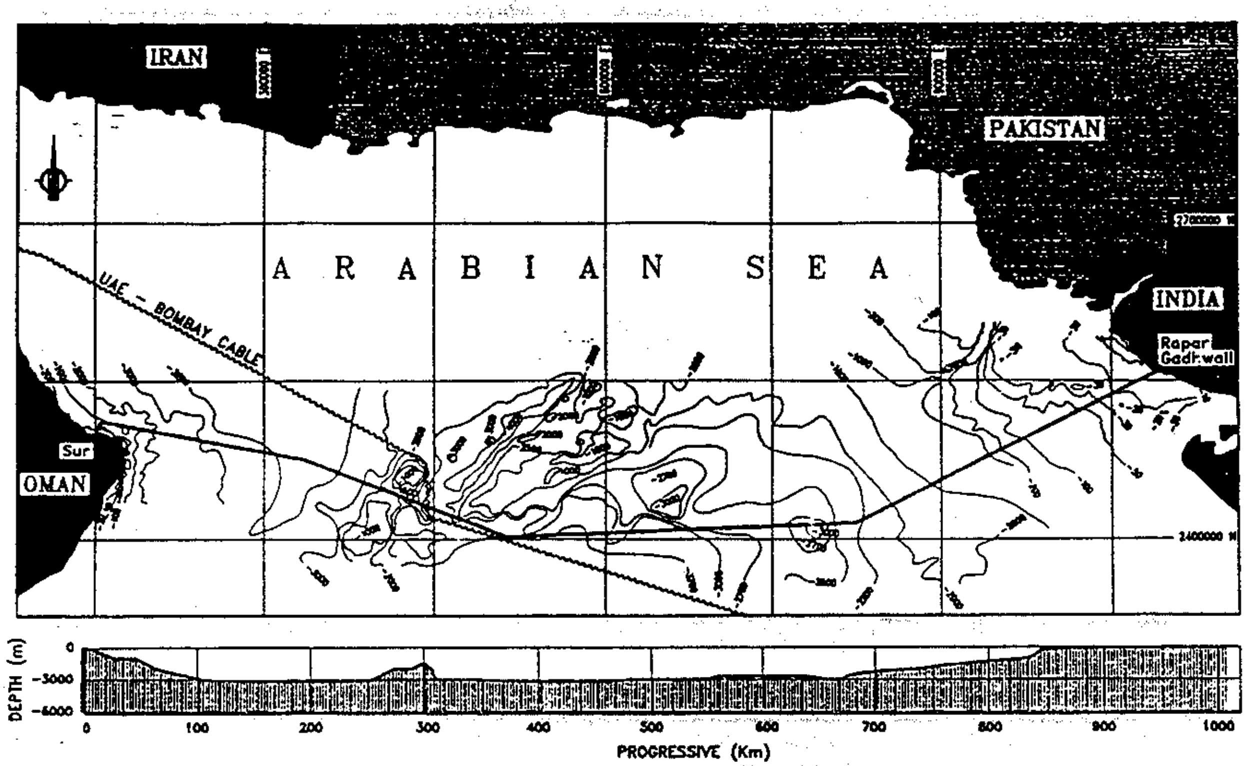


Fig. 4 - The OMAN-INDIA gas pipeline - A unic technical challenge

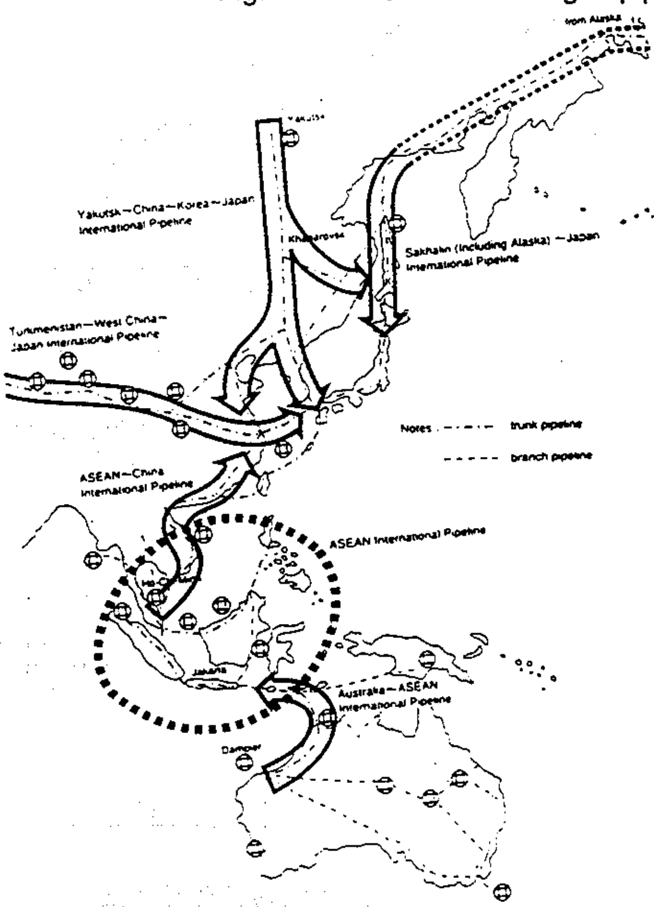


Fig. 5 - The Trans-Asian Natural Gas Pipeline Project

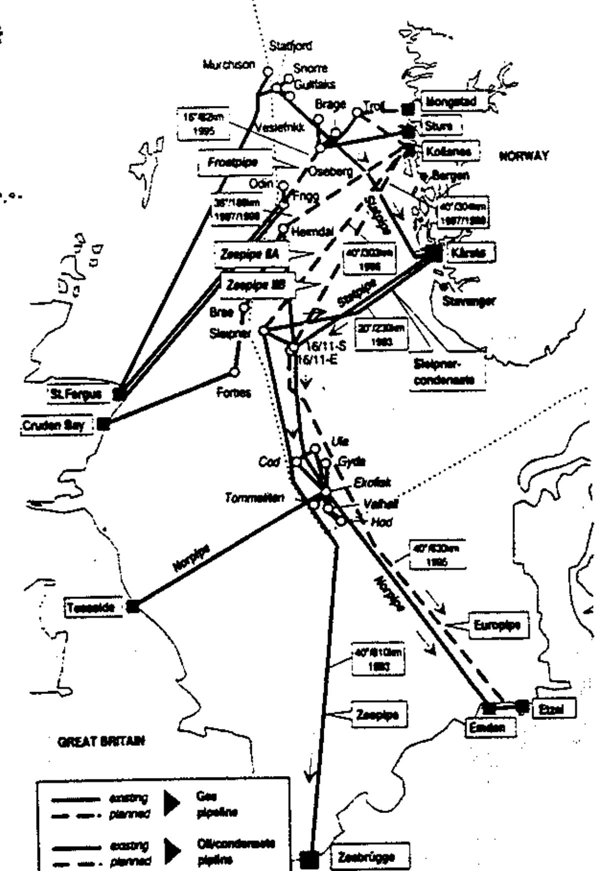
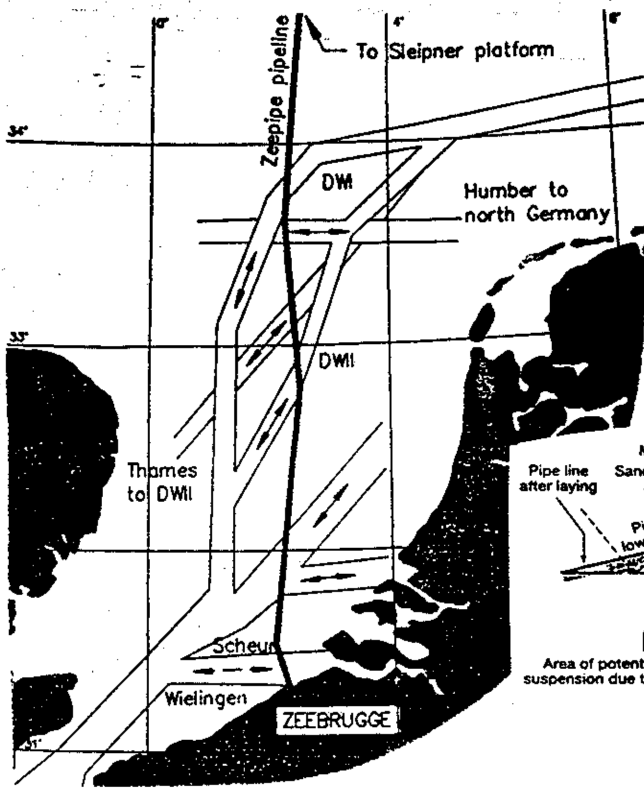
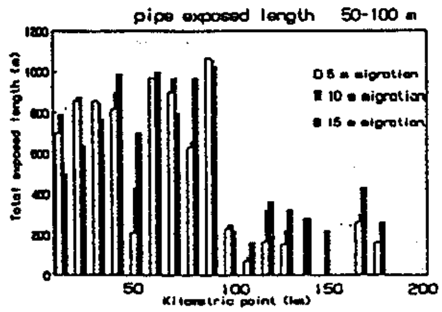


Fig. 6 - The North Sea Natural Gas and Oil Pipeline Network





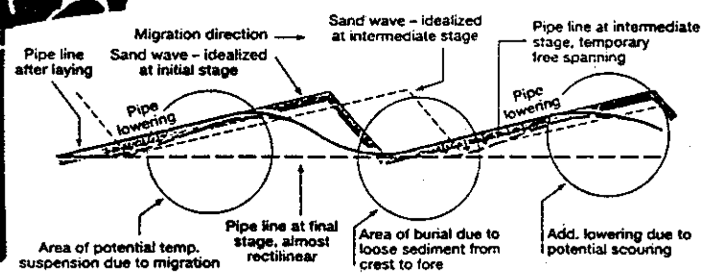
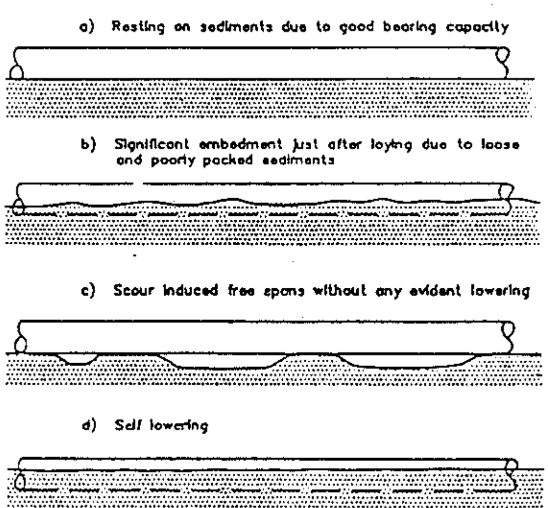


Fig. 7 - Shipping lanes and channels in the Southern North sea crossed by Zeepipe

Fig. 8 - Schematic pipeline structural behaviour during sand wave migration



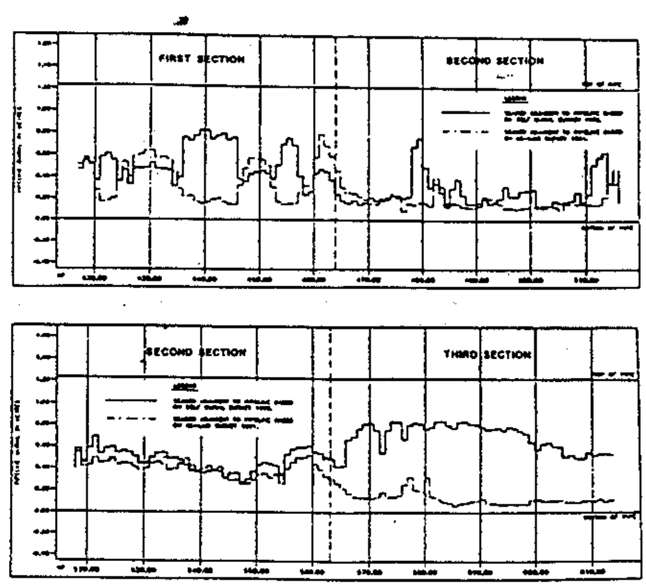


Fig. 9 - Different scenarios in formulating design criteria for on-bottom stability

Fig. 10 - The summary of results of self lowering survey after one winter season on Zeepipe pipeline in the Dutch Sector

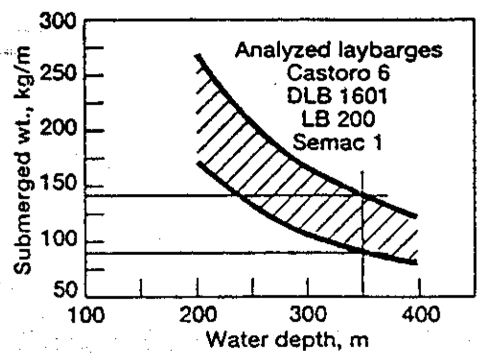


Fig. 11 - Maximum layable submerged weight at 90% laybarge capacity (1993)

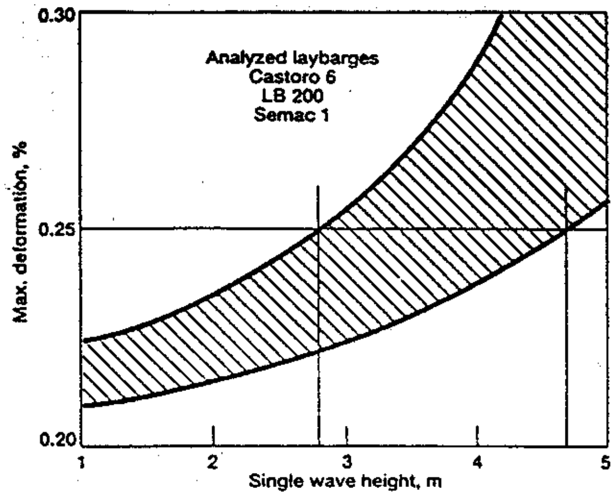
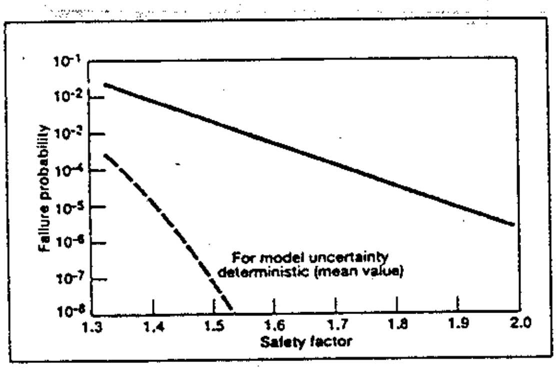


Fig. 12 - Susceptibility of pipelay to wave induced laybarge dynamics in terms of peak strains



Uncertainty measures

Value	Distribution	Mean	Std. deviation
Diameter	Normal	$D_{nom} + 0.5$ $(\Delta D_{max} + \Delta D_{min})$	0.25 $(\Delta D_{max} + \Delta D_{min})$
Thickness	Normal	$1.05\ t_{nom}$	$0.025\ t_{nom}$
Specified min. yield stress	Log-normal	$1.07\sigma_y$	$0.04\sigma_y$
Out of round.	Log-normal	$7.4\ 10^{-3}$	$7.4\ 10^{-4}$
Model uncert.	Normal	0.9	0.09

Fig. 13 - Safety factors versus probability of collapse using reliability methods

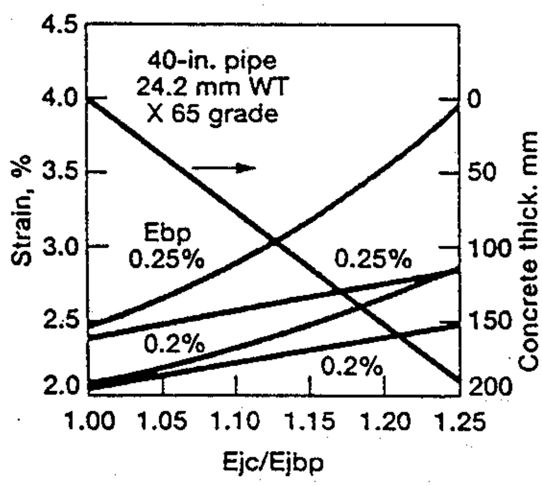
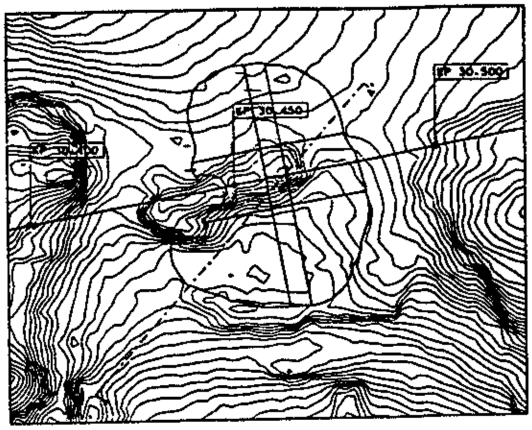


Fig. 14 - Strain Concentration of field joint due to concrete coating thickness



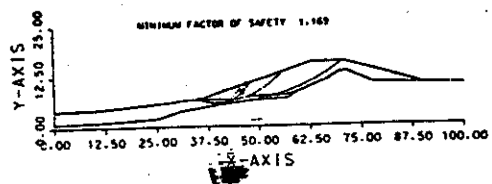


Fig. 15 - Stability analysis of rock berms bearing the pipeline at mid-span

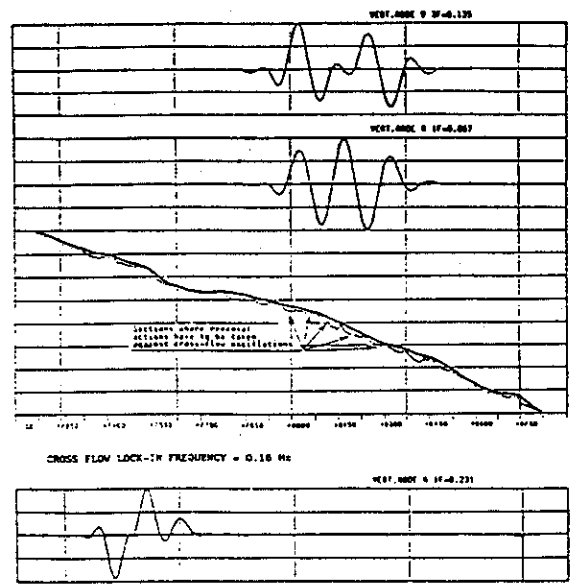


Fig.16 - Multi-span dynamics and associated free span intervention work criteria

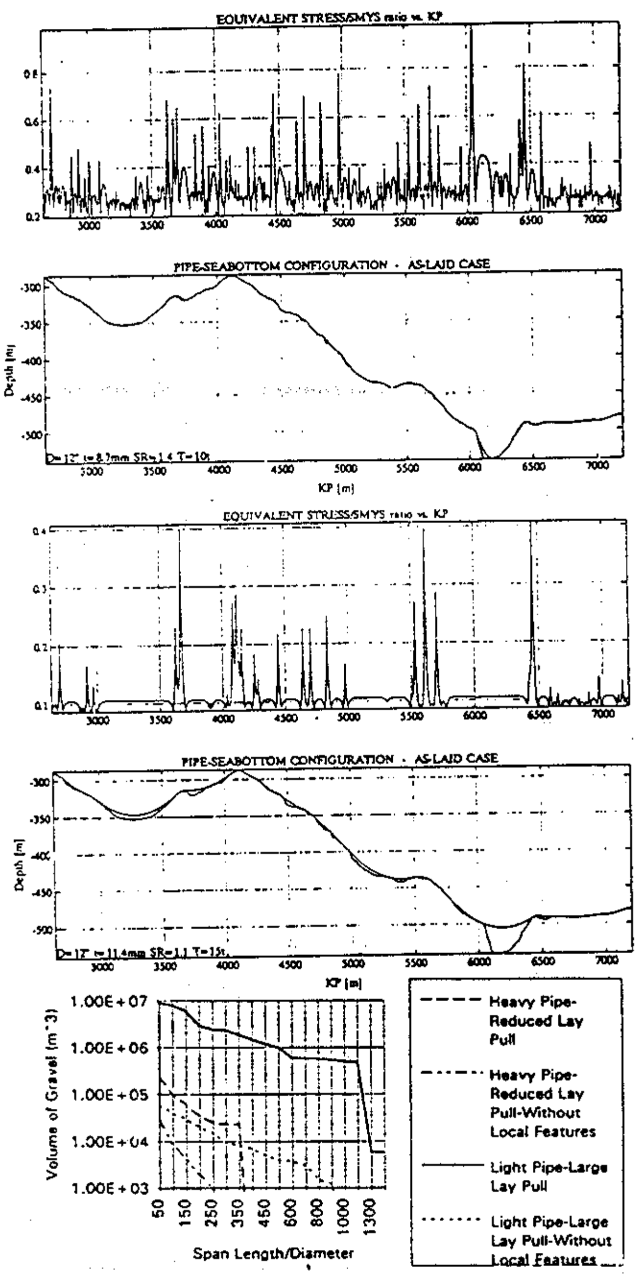


Fig. 17 - State of equilibrium on uneven seabeds and required gravel volumes for free span correction

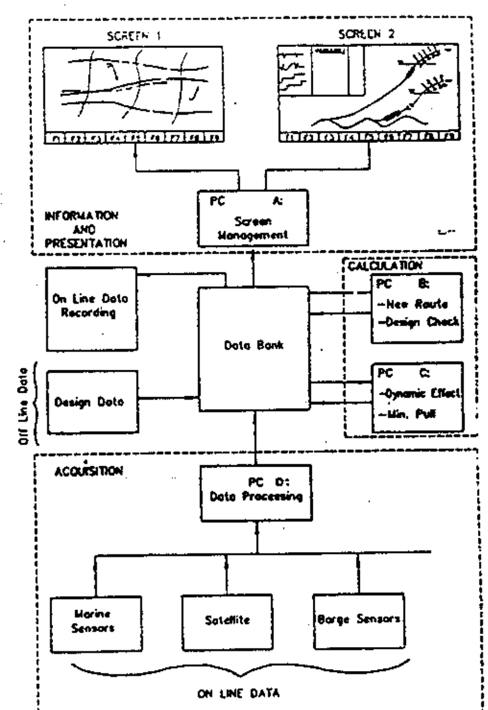


Fig. 18 - Assisted laying to improve laying rate and the compliance with difficult route alignments

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Rodriguez	Julie	Epic Divers	1556 MacArthur Ave.	Harvey	LA	70058
Rodriguez	Roger	Epic Divers	1556 MacArthur Ave	Harvey	LA	
Cieutat	Joe	Epic Divers, Inc.	1556 MacArthur Ave.	Harvey	LA	70058
Fleming	Dave	Epic Divers, Inc.	1556 MacArthur Ave.	Harvey	LA	70058
Bailey	B.E.	Erçon Development	8800 Jameel, Suite 190	Houston	TX	77040
Lewis	John	Ercon Development Co.	8800 Jameel Rd., Suite 190	Houston	TX	77040
Mars	Rex	Ercon Development Co.	8800 Jameel Rd. Ste. 190	Houston	TX	77040
Mars	Rex	Ercon Development Co.	8800 Jameel Rd., Suite 190	Houston	TX	77040
Thompson	W. Les	Ercon Development Co.	8800 Jameel Rd. Ste. 190	Houston	TX	77040
Allman	Scott	Exxon	P.O. Box 61707	New Orleans	LA	70161-1707
Henley	Vernard W.	Exxon	P.O. Box 61707	New Orleans	LA	70161-1707
Holt	Jack B.	Exxon Company U.S.A.	800 Bell St.	Houston	TX	77002
Vidrine, President	S. Joe	Flange Skillets Int'l., Inc.	P.O. Box 0701	Washington	LA	70589
Prudhomme	Joy	Flange Skillets International	568 Chickasaw Dr.	Opelousas	LA	70570
Gilbert	Danny	G&G Marine, Inc.	25933 Budde Rd.	The Woodlands	TX	77380
Shapiro	Steve	General Marine Leasing	P.O. Box 740957	New Orleans	LA	70174
Bergman	Larry	Global Divers & Contr., Inc.	P.O. Box 10840	New Iberia	LA	70562
Merriman	Bob	Global Divers & Contr., Inc.	P.O. Box 2518	Houma	LA	70361
Nelson	Don	Global Divers & Contr., Inc.	P.O. Box 2518	Houma	LA	70361
Broussard	Craig	Global Industries	107 Global Circle	Lafayette	LA	70503
Dore	Jim	Global Industries, Ltd.	P.O. Box 31936	Lafayette	LA	70593-1936
Gray	Byron	Global Industries, Ltd.	2900 Energy Ctr., 1100 Poydras	New Orleans	LA	70163

LIST OF ATTENDEES

LastName	FirstName	Co/Affiliation	Address	City	St	Zip
McClure	Lawrence C.	Global Industries, Ltd.	107 Global Circle	Lafayette	LA	70560
Eckert	Don	Global Pipelines	P.O. Box 2518	Houma	LA	70361
Hazen	Frank	Gulf Coast Marine Divers	840 Fairfield Ave.	Gretna	LA	70056-7628
Brentano	Keith	Gulf Star Holdings, Inc.	3838 N. Causeway, Suite 3150	Metairie	LA	70002
Gremillion	Frank	Gulf Star Holdings, Inc.	3838 N. Causeway, Suite 3150	Metairie	LA	70002
Lochte	Glen	H.O. Mohr Research & Engineering, Inc.	Northwoods Ind.Park W., 12237 FM 529	Houston	TX	77041
Mohr	Harvey	H.O. Mohr Research & Engineering, Inc.	Northwoods Ind.Park W., 12237 FM 529	Houston	TX	77041
Camp	Kathy	Hall-Houston Oil Company	700 Louisiana, Suite 2100	Houston	TX	77002
Cheramie	Keith	Harvey Gulf International Marine	3817 Spencer St.	Harvey	LA	70058
Holland	Ed	HBH, Inc.	P.O. Box 55	Harvey	LA	70058
Hughes	Dan	HBH, Inc.	P.O. Box 55	Harvey	LA	70059
Morgan	Richard	Hydratight	2007A Preston	Pasadena	TX	77503
Teller	Jim	Hydratight	2007A Preston Rd.	Pasadena	TX	77503
Cooper	Al	Hydrotech Systems, Inc.	11500 N.W. Freeway	Houston	TX	77092
Wittman	Robert "Bob"	Hydrotech Systems, Inc.	11500 N.W. Freeway	Houston	TX	77092
Boss	Terry	INGAA	555 13th St. NW, Suite 300 West	Washington	DC	20004
Kinne	Ted	INGAA	555 13th St. NW, Suite 300 West	Washington	DC	20004
Marzolf	Tim	Innovatum, Inc.	2020 Southwest Freeway #203	Houston	TX	77098-4807
German	Phil	Intec Engineering, Inc.	15600 JFK Blvd, 9th Floor	Houston	TX	77032
Cheatham III	John H.	Interstate Natural Gas Assn. of America	555 13th Street, N.W. Suite 300W	Washington	DC	20004
Pierce	Jennifer M.E.	Interstate Natural Gas Assn. of America	555 13th Street, N.W. Suite 300W	Washington	DC	20004
Warman	David J.	Iroquois Gas	1 Corporate Dr., Suite 600	Shelton	CT	06460
Connor	Ms. Jodie	J. Connor Consulting, Inc.	16225 Park Ten Place, Ste 500	Houston	TX	77084
Watkins	Wes	J. Connor Consulting, Inc.	16225 Park Ten Place, Ste 500	Houston	TX	77084
Hair	J.D.	J.D.Hair & Associates	2815 East Skelly Dr., Suite 820	Tulsa	OK	74105-6251
Evans	Damon	J.P. Kenny International, Inc.	5100 Westheimer	Houston	TX	77056
Fu	Lang	J.P. Kenny International, Inc.	5100 Westheimer	Houston	TX	77056
Wright	Howard	J.P. Kenny International, Inc.	5100 Westheimer	Houston	TX	77056
Caldwell	Joe	Joe Caldwell & Associates	2111 Wilson Blvd., Suite 700	Arlington	VA	22201
Cormier	Lionel J.	John E. Chance & Assoc.	200 Dulles Drive	Lafayette	LA	70517
Latiolais	Jim	John E. Chance & Assoc.	200 Dulles Drive	Lafayette	LA	70517
O'Neal	James P.	John E. Chance & Assoc.	200 Dulles Drive	Lafayette	LA	70506
Tenney	Shuble	John E. Chance & Assoc.	200 Dulles Drive	Lafayette	LA	70506
Butcher	Ron	John E. Chance & Associates	10607 Haddington	Houston	TX	77043
Keener	Danny	John E. Chance & Associates	10607 Haddington	Houston	TX	77043
Mantell	Frank	John E. Chance & Associates	200 Dulles Drive	Lafayette	LA	70506
Williams	Richard	John E. Chance & Associates	10607 Haddington	Houston	TX	77043
Copeland	Steve	Kerr-McGee Corp.	P.O. Box 39400	Lafayette	LA	70593-9400
Loyd	Ernie	Kerr-McGee Corp.	P.O. Box 39400	Lafayette	LA	70593-9400

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LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Bradford	Cary V.	Kerr-McGee Corporation	P.O. Box 39400	Lafayette	LA	
Sorey	Jon	Koch Gateway Pipeline	19674 Mitch Rd.	Bogalusa	LA	704127
Presgrove	Cody	Koch Industries Inc.	4111 East 37th north	Wichita	KS	67220
St.Germain	Wayne	Koch Industries Inc.	4111 E. 37th St. North	Wichita	KS	67220
Bomba	John G.	Kvaerner R.J. Brown & Associates	1111 Wilcrest Green #250	Houston	TX	77042
Brown	R.J.	Kvaerner R.J. Brown & Associates	1111 Wilcrest Green #250	Houston	TX	77042
Raborn	Gene	Kvaerner R.J. Brown & Associates	1111 Wilcrest Green #250	Houston	TX	77042
Swan	Martha A.	La. Dept. of Natural Resources	P.O. Box 94396	Baton Rouge	LA	70804-9396
Hinojosa	Mariano G.	La. Dept. of Natural Resources-Off.of Cons.	P.O. Box 94275	Baton Rouge	LA	70804-9275
Arabic	Dana	La. Dept. of Public Safety				
Dunham	Fred O.	La. Dept. of Wildlife & Fisheries	P.O. Box 98000	Baton Rouge	LA	70898-9000
Guidry	Roland	La. Oil Spill Coordinator's Office				
Casadaban	Rene' L.	Land and Marine, Inc.	15311 W. Vantage Pkwy, Suite 134	Houston	TX	77032
Lammert	Wayne	Leviathan Gas Pipeline Partners LLC	7400 Texas Commerce Tower, 600 Travis	Houston	TX	77002
Buteau	Mark	LL&E	909 Poydras Street	New Orleans	LA	70112
Price	Larry K.	LL&E	909 Poydras Street	New Orleans	LA	70112
Arnondin	Chuck	LOOP Inc.	One Seine Court, Box 6638	New Orleans	LA	70174
Hair	Buzz	Louis J. Capozzoli & Associates	10555 Airline Highway	Baton Rouge	LA	70816
Sauls	David	Louis J. Capozzoli & Associates	10555 Airline Highway	Baton Rouge	LA	70816
Frey	David	Louisiana One Call				
Williams	Bobby J.	M & H Offshore	217 E.Kaliste Saloom Rd.,Ste 107	Lafayette	LA	70508
James	Michael G.	Magellan Marine	3350 Ridgelake Dr.	Metairie	LA	70002
Naylon	John	Magellan Marine Inc.	3350 Ridgelake Dr.	Metairie	LA	70002
Gragg	Michael	Marathon Oil Company	P.O. Box 4816	Houston	TX	77210
Harvey	Carol	Marathon Oil Company	7400 S. Broadway	Littleton	CO	80122
Broussard	Dwain	Marathon Pipe Line Company	P.O. Box 53266	Lafayette	LA	70505-3266
Walter	Sheri A.	Marathon Pipe Line Company	P.O. Box 4816	Houston	TX	77210
Yocom	Rick	Marathon Pipe Line Company	P.O. Box 791	Venice	LA	77091
Ballassi	Salvatore	Marine Board	24 Wellington Ct	Missouri City	TX	77459
Gorell	Fred	Marine Spill Response Corp.	901 Lakeshore Dr., Ste 900	Lake Charles	LA	70601
Barousse	Brett	McDermott	3000 Mark Dr.	Morgan City	LA	70380
Boudreaux	Francis J.	McDermott	P.O. Box 188	Morgan City	LA	70380
Danos	John H.	McDermott	P.O. Box 188	Morgan City	LA	70380
Gernon	George O.	McDermott	111 Parnell Drive	Houma	LA	70360
Hebert	Chuck	McDermott	P.O. Box 188	Morgan City	LA	70380
Houser	Dan	McDermott	P.O. Box 188	Morgan City	LA	70380
Lee	Griff C.	McDermott	P.O. Box 60035	New Orleans	LA	70160
Mullen	Jim	McDermott	P.O. Box 188	Morgan City	LA	70380
Proper, Jr.	Leon E.	McDermott	P.O. Box 188	Morgan City	LA	70381

LIST OF ATTENDEES

LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Rose	Bill	McDermott	P.O. Box 8746	Metairie	LA	70011
Sanzgiri	Linus	McDermott	1010 Common St.	New Orleans	LA	70112
Spivey	Larry	McDermott	4826 Walker Rd.	Jonesboro	LA	71251
Wilkins	J.	McDermott	P.O. Box 60035	New Orleans	LA	70160
Becnel	Thomas G.	Meridian Oil Inc.	400 N. Sam Houston Pkwy E., Suite 1200	Houston	LA	
Alvarado	Alex	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Anderson	Carl	Minerals Management Service	381 Elden Street, MS-4700	Herndon	VA	22070-4817
Bartholomew	Henry	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Bell	Theresa	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
Britton	Autry	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Clingan	Richard	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
Conner	George	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Danenberger	E.P.	Minerals Management Service	381 Elden Street, MS-4700	Herndon	VA	22070-4817
Dyhrkopp	Felix	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Fagot	Caryl	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Faust	Katherine	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Froomer	Norman	Minerals Management Service	1201 Elmwood Park Blvd - MS 5400	New Orleans	LA	70123-2394
Grant	James R.	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
Guidry	John	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Howard	Donald	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Jones	Alvin L.	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Lane	James	Minerals Management Service	381 Elden Street, MS-4700	Herndon	VA	22070-4817
Marchese	Jean	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Martin	William	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Masri	Nabil	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
McCarthy	John	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
McIntosh	Doug	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Monahan	Leslie	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
Oynes	Chris C.	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Patton	Frank	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Regg	Jim	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Richardson	G. Ed	Minerals Management Service	1201 Elmwood Park Blvd. (MS 5440)	New Orleans	LA	70123
Shah	Arvind	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123
Smith	Charles E.	Minerals Management Service	381 Elden Street, MS-4700	Herndon	VA	22070-4817
Smith	John	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	93010-6064
Stanek	Catherine	Minerals Management Service	770 Paseo Camarillo	Camarillo	CA	
Stauffer	Kent	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Torres	Francis	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Treadaway	Geraldine	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394

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LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Wiese	Jeffrey D.	Minerals Management Service	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Maranto	Ann	Minerals Management Service, P/L Division	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Williamson	Warren	Minerals Management Service, P/L Division	1201 Elmwood Park Blvd.	New Orleans	LA	70123-2394
Currie	David M.	Mobil Exp. & Prod. Tech.Ctr.	13777 Midway Rd.	Dallas	TX	75244
Casey	Cathey	Mobil Exp. & Prod. U.S., Inc.	1250 Poydras St.	New Orleans	LA	70113
Killeen	Joe	Mobil Exp. & Prod. U.S., Inc.	1250 Poydras Bldg.	New Orleans	LA	70113-1892
Robinson	John T.	Mobil Exp. & Prod. U.S., Inc.	1250 Poydras St.	New Orleans	LA	70113
Steinwinder	Dottie	Mobil Exp. & Prod. U.S., Inc.	1250 Poydras St.	New Orleans	LA	70113
Terry	Louise	Mobil Exp. & Prod. U.S., Inc.	1250 Poydras	New Orleans	LA	70113
LeBlanc	Steven J.H.	Mobil R & D Corporation	P.O. Box 819047	Dallas	TX	75381-9047
Litzelfelner	Joe	MPC ***				
Von Tungle	Rob	MPC ***				
Smith	Ray	National Energy Board of Canada	311 6th Avenue SW	Calgary, Alberta	Canada	T2P3H2
Noel	Mike	National Response Corp.	2203 Timberloch Pl., Ste 234	The Woodlands	TX	77380
Wood	Alvin E.	National Response Corp.	2203 Timberloch Pl., Ste 234	The Woodlands	TX	77380
Fontenot	Dale	Natural Gas Pipeline	HC 69 Box 143	Cameron	LA	70631
Miley	John	Natural Gas Pipeline	HC 69 Box 143	Cameron	LA	70631
O'Brien	Dave	Natural Gas Pipeline	HC 69 Box 143	Cameron	LA	70631
Pimmel	Tim	Natural Gas Pipeline	HC 69 Box 143	Cameron	LA	70631
Bennett	Philip	Natural Gas Pipeline Co.	701 East 22nd Street	Lombard	IL	60148-5072
Walter	Donald J.	Naval Research Lab	Seafloor Sciences Branch	Stennis Sp.Ctr.	MS	39529-5004
Richard	C.J.	Norman Offshore Pipelines, Inc.	P.O. Box 53907	Lafayette	LA	70505
Dabagian	Steven	Ocean Systems Int'l, Inc.	P.O. Box 46461	St.Petersburg	FL	33741
Wagner	Scott	Oceaneering	P.O. Box 929	Tomball	TX	77377-0929
Missig	Tom	Oceaneering Int., Inc.	P.O. Box 929	Tomball	TX	77377-0929
Bech	Steve	Oceans Technology, Inc.	3836 Spencer Street	Harvey	LA	70058
Kane	Gary	Oceans Technology, Inc.	3836 Spencer Street	Harvey	LA	70058
Leask	Linden J.	Oceans Technology, Inc.	3836 Spencer Street	Harvey	LA	70058
Charles	Randy	Oryx Energy Company	P.O. Box 2880	Dallas	TX	75221
Parker	Wanda	Oryx Energy Company	P.O. Box 2880	Dallas	TX	75221
Smith	W.W.	Pacific Coast Energy Corporation	4436 Boban Drive	Nanaimo, B.C.	Canada	V9T5V9
Meyer	Jim E.	Panhandle Eastern Corp.	5400 Westheimer	Houston	TX	77056
Simkin	Curt	Panhandle Eastern Corp.	5400 Westheimer	Houston	TX	77056
Brickey	Mike	Panhandle Eastern Corporation	P.O. Box 1642	Houston	TX	77056-5310
Drake	J. Andrew	Panhandle Eastern Corporation	5444 Westheimer, Rm. 598	Houston	TX	77056
Porter, P.E.	Don C.	Panhandle Eastern Pipe Line	5444 Westheimer Street, Suite 699	Houston	TX	77056
Bright	Bob	Pennzoil Co	P.O. Box 51843	Lafayette	LA	70505
Watson	Larry	Phillips Petroleum	P.O. Box 51107	Lafayette	LA	70505
Donnell	Bruce	Pipeline Consultants	255 Blue Ridge Dr.	Carencro	LA	70520

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LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Krams	David	Port of Corpus Christi Authority	222 Power St	Corpus Christi	TX	78403
Kane	Pat	Power Performance	201 Energy Parkway Suite 205	Lafayette	LA	70508
Breaux	Kenneth E.	Project Consulting Services, Inc.	3300 W. Esplanade Ave.S., Suite 603	Metairie	LA	70002-7406
Romero	Eric	Project Consulting Services, Inc.	3300 W. Esplanade Ave.S., Suite 603	Metairie	LA	70002-7406
Vogt	Gary	Project Consulting Services, Inc.	3300 W. Esplanade Ave.S., Suite 603	Metairie	LA	70002-7406
Herring	Barry	Quality Tubing				
Fusselman	D. Scott	Rentec International	19424 Park Row 100	Houston	TX	77084
McAvoy	Johnny	S & J Diving Inc.	P.O. Box 34413	Houston	TX	77234-4413
Reuser	Hank	Shaw Pipe	2408 Timberloch Pl. Bldg C-8	The Woodlands	TX	77381
Arnold	Peter	Shell Offshore Inc.	914 Beau Chene Dr.	Mandeville	LA	70471
Burglass	Andy	Shell Offshore Inc.	P.O. Box 61933	New Orleans	LA	
Mire	Mike	Shell Offshore Inc.	P.O. Box 61933	New Orleans	LA	
Olivares	Tino	Shell Offshore Inc.	P.O. Box 61933 Room #2435	New Orleans	LA	
Velez	Peter	Shell Offshore Inc.	P.O. Box 61933	New Orleans	LA	
Barry	Don W.	Shell Oil Company	P.O. Box 2099	Houston	TX	77252-2099
Broussard	Gweneyette	Shell Oil Company	777 Walker Street-TSP-1466	Houston	TX	77002
Coyne	Michael J.	Shell Oil Company	3406 Deerland Ct.	Kingwood	TX	77345
Korpal	J.M.	Shell Oil Company	777 Walker St.	Houston	TX	77002
Miller	J.D. "Dave"	Shell Oil Company	P.O. Box 2099 1320 TSP	Houston	TX	77345
Preli	Tom	Shell Oil Company	777 Walker Street, P.O. Box 2099	Houston	TX	77252-2099
Zimmerman	Gary	Shell Oil Company	P.O. Box 2099	Houston	TX	77252-2099
Goudy	Eric	Shell Pipe Line Corp.	P.O. Box 52163	New Orleans	LA	70152
Hass	J.S. "Scott"	Shell Pipe Line Corporation	P.O. Box 52163	New Orleans	LA	70152
Ledet	Kevin	Shell Pipe Line Corporation	P.O. Box 52163	New Orleans	LA	70152
Van Laere	Richard J.	Shell Pipe Line Corporation	P.O. Box 52163	New Orleans	LA	70152
Miniclier, Esq.	Paul C.	Simon, Peragrine, Smith & Redfearn	1100 Poydras St., Suite 3000	New Orleans	LA	70163
Bruschi	Roberti	Snamprogetti, Fano, Italy				
Chamblee	Cliff	SONSUB, Inc.	10905 Metronome	Houston	TX	77043
Creel	Gerald D.	Southern Natural Gas	P.O. Box 147	Chalmette	LA	70044
Peters	Kenneth C.	Southern Natural Gas	P.O. Box 2563	Birmingham	AL	35202-2563
Higgins	Thomas (Tom) F.	Southern Natural Gas Co.	P.O. Drawer 303	Erath	LA	70533
Dye	Jeff	Southern Natural Gas Company	P.O. Box 2563	Birmingham	AL	35202-2563
Ferer	David	Southern Natural Gas Company	P.O. Box 2563	Birmingham	AL	35202-2563
Healy	Richard C.	Southern Natural Gas Company	P.O. Box 2563	Birmingham	AL	35202-2563
McDaniel	Kelvin	Southern Natural Gas Company	P.O. Box 2563	Birmingham	AL	35202-2563
Popelar	Dr. Carl H.	Southwest Research Inst.	P.O. Drawer 28510	San Antonio	TX	78228-0510
Smith	Marina Q.	Southwest Research Institute	6220 Culebra Road	San Antonio	TX	
Bucceri	Thomas R.	St.of Alaska,Div.of Oil & Gas	P.O. Box 107034	Anchorage	AK	99510-7034
Fowler, Ph.D., P.E	Joe R.	Stress Engineering Services, Inc.	13800 Westfair East	Houston	TX	77041-1101

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LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Hux	Will F.	Stroud Diving	5030 Old Kings Rd.	Jacksonville	FL	32254
Maged	Kassem	Sub Sea Int'l, Inc.	701 Engineers Rd.	Belle Chasse	LA	70037
Mermis	Jim	Sub Sea Int'l, Inc.	701 Engineers Rd.	Belle Chasse	LA	70037
Watt	Andy	Sub Sea International	701 Engineers Rd.	Belle Chasse	LA	70037
Angel	Thomas M.	Submar, Inc.	800 Dunn St	Houma	LA	70360
Angel	Thomas M.	Submar, Inc.	800 Dunn St	Houma	LA	70360
Crain	Larry	Submar, Inc.	800 Dunn St	Houma	LA	70360
Foley	Edward F.	SUBMAR, Inc.	800 Dunn St.	Houma	LA	70360
Poiencot	Keith	Submar, Inc.	800 Dunn St	Houma	LA	70360
Marshall	Paul	SubSea International	345 St. Joseph Apt. 208	New Orleans	LA	
Renear	Dennis	SubSea International, Inc.	701 Engineers Rd.	Belle Chasse	LA	70037
Blank	Haynes	Tejas Power Corp.	200 Westlake Park Blvd., Suite 1000	Houston	TX	77079
Broussard	Larry	Tenneco Gas Pipeline	1010 Milam - T-1338A	Houston	TX	77002
Harrison	Frank G.	Tenneco Gas Pipeline	1010 Milam - T-1338A	Houston	TX	77002
Kennedy	Brian	Tenneco Gas Pipeline	1010 Milam - T-1335A	Houston	TX	77002
Richardson	Albert T.	Tenneco Gas Pipeline	P.O. Box 2511	Houston	TX	77252
Tennison	Dan E.	Tenneco Gas Pipeline	1010 Milam - T-1330A	Houston	TX	77002
Whitney	Chris	Tenneco Gas Pipeline	1010 Milam, Suite 1424S	Houston	TX	77002
Zurcher	John	Tenneco Gas Pipeline	1010 Milam, Suite 1424S	Houston	TX	77002
Davis	Michael J.	Tennessee Gas Pipeline	224 Aviation Road	Houma	LA	
Nunnally	Jim	Tennessee Gas Pipeline	1115 Regal Row	Houma	LA	70360
Winters	Bob	Tennessee Gas Pipeline Co.	P.O. Box 2511	Houston	TX	77252-2511
Butterworth, Esq.	Michael M.	Terriberry, Carroll & Yancey, L.L.P.	3100 Energy Center, 1100 Poydras	New Orleans	LA	70163-3100
Chandra	Tapan	Texaco	P.O. Box 430	Bellaire	TX	77402
Abadin	Jose	Texaco Exploration & Prod.	P.O. Box 60252	New Orleans	LA	70160
Becnel	Miles	Texaco Exploration & Prod.	P.O. Box 60252	New Orleans	LA	70160
Houlder	C. James	Texaco Exploration & Prod.	P.O. Box 60252	New Orleans	LA	70160
Pastoret	Ron	Texaco Exploration & Prod.	P.O. Box 60252	New Orleans	LA	70160
Subik	Dan	Texaco Exploration & Prod.	P.O. Box 60252	New Orleans	LA	70160
Frederick	Paul	Texas Gas Transmission Cor.	P.O. Box 51969	Lafayette	LA	
Griffin, P.E., L.S.	John R.	Texas Gas Transmission Corp.	3800 Frederica Street	Owensboro	KY	42301
Smith, P.E.	Michael R.	Texas Gas Transmission Corp.	3800 Frederica Street	Owensboro	KY	42301
Freytes	Manuel	Texas General Land Office	6300 Ocean Dr., Sea Breeze Hall, Suite #3	Corpus Christi	TX	78412
McDaniel	Mary	Texas R.R. Commission				
Fahrenthold	Gerry	The Home Insurance Co.	2925 Briarpark, Suite 800	Houston	TX	77042
Dokmo	Richard C.	The Tapecoat Company	1527 Lyons St.	Evanston	IL	60204
Hills	James R.	Transco Energy	H.C. 69 Box 183	Cameron	LA	
Hoepner	Ron	Transco Gas Pipeline	P.O. Box 1396	Houston	TX	77251-1396
Owens	James E.	Transcontinental Gas P/L Corp.	P.O. Box 10286	Corpus Christi	TX	78460

LIST OF ATTENDEES

LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Treme	Winfard A.	Transcontinental Gas P/L Corp.	P.O. Box 316	Markham	TX	
Davenport	Mark T.	Transcontinental Gas Pipe Line Corp.	2800 Post Oak Blvd.	Houston	TX	
Houston	Jim	Transcontinental Gas Pipe Line Corp.	110 Cypress Station Drive, Suite 151	Houston	TX	77090
Kerley	Andrew	Transcontinental Gas Pipe Line Corp.	5600 Rock Road	Coden	AL	
Linn	Craig M.	Transcontinental Gas Pipe Line Corp.	P.O. Box 1396	Houston	TX	77251
Pittman	Chuck	Transcontinental Gas Pipe Line Corp.	110 Cypress Station Drive Suite 151	Houston	TX	77090
Strub	Joan	Transcontinental Gas Pipe Line Corp.	110 Cypress Station Drive Suite 151	Houston	TX	77090
OOC Employee		Transworld Oil, U.S.A., Inc.	654 North Belt East, Suite 400	Houston	TX	77060
Adams	John	Trunkline Gas Company	P.O. Box 1642	Houston	TX	77251-1642
Anderson	Mark	Trunkline Gas Company	P.O. Box 1642	Houston	TX	77251-1642
Lehman	James (Jim)	Trunkline Gas Company	P.O. Box 69	Centerville	LA	70522-0069
Moody	Bob	Trunkline Gas Company	P.O. Box 1642	Houston	TX	77251-1642
Shellhouse	Dave	Trunkline Gas Company	P.O. Box 1642	Houston	TX	77251-1642
Casey	Ernie	U.L.S.I. Houston				
Flanigan	John	U.S. Army Corps of Engineers	P.O. Box 60267	New Orleans	LA	70160
Vignes	Julie Dorcey	U.S. Army Corps of Engineers	P.O. Box 60267	New Orleans	LA	70160
Calhoun	Capt. James	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Ehrhart	Mr. John	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Illg	Lt. Jim	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Johnson	Mr. Phil	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Keegan	Cmdr. Tim	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Leonard	Lt. Joe	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Obernesser	Lt. Cmdr. Jim	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Robb	Lt.Cmdr. Kevin	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Schoen	Lt. Bob	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Smith	Mr. John	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Paris	Lt. Commander	U.S. Coast Guard	501 Magazine St.	New Orleans	LA	70130-3396
Barber	Melanie	U.S. DOT	400 Seventh Street, SW	Washington	DC	20005
De Leon	Ceasar	U.S. DOT	400 Seventh Street, SW	Washington	DC	20005
Gerald	Stacey	U.S. DOT	400 Seventh Street, SW	Washington	DC	20005
Gute	Bill	U.S. DOT	400 Seventh Street, SW	Washington	DC	20005
Herrick	L.E.	U.S. DOT	400 Seventh Street, SW	Washington	DC	20005
Thomas	James	U.S. DOT	2320 Labranch #2116	Houston	TX	77004
Bertges	Bill	U.S. DOT Southwest Region	33780 Marion Drive	Denham Spring	LA	70726
Tenley	George	U.S. DOT, Office of Pipeline Safety	400 Seventh Street, SW	Washington	DC	20005
Wilder	John R.	Union Pacific Resources	P.O. Box 7 - MS 3803	Ft. Worth	TX	76101-0001
Gann	Mike	Union Pacific Resources Co.	801 Cherry Street	Fort Worth	TX	76102
Howes	Jack L.	UNOCAL	4021-4023 Ambassador Caffery Pkwy.	Lafayette	LA	70593
Swoboda	Jay	VMW Industries	P.O. Box 1939	Victoria	TX	77902

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LastName	FirstName	Co/Affiliation	Address	City	St	Zip
Swoboda	John J.	VMW Industries	7303 Houston Hwy	Victoria	TX	77902
Andersen	Len	Wet Welding	P.O. Box 1529	New York	NY	10116
Wolaver	Morgan	Wimpol, Inc.	10607 Haddington	Houston	TX	77043